BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: : Docket Number

REMEDYING UNDUE DISCRIMINATION : RM01-12-000

THROUGH OPEN ACCESS TRANSMISSION :

SERVICE AND STANDARD ELECTRICITY :

MARKET DESIGN :

STANDARDIZATION OF GENERATOR : Docket Number

INTERCONNECTION AGREEMENTS : RM02-1-000

AND PROCEDURES :

STANDARDIZATION OF SMALL GENERATOR :

INTERCONNECTION AGREEMENTS AND : Docket Number

PROCEDURES, ADVANCE NOTICE OF : RM02-12-000

PROPOSED RULEMAKING :

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Commission Meeting Room

Federal Energy Regulatory Commission

888 First Street, NE

Washington, D.C.

Tuesday, January 21, 2003

The above-entitled matter came on for technical conference, pursuant to notice, at 10:00 a.m., Patrick Rooney, Office of Markets Tariffs and Rates presiding.

APPEARANCES:

At the Tables:

Chairman Pat Wood, III

Mark Hegerle, Office of Markets Tariffs and Rates

Roland Wentworth, Office of Markets Tariffs and Rates

Bruce Poole, Office of Markets Tariffs and Rates

Norma McOmber, Office of Markets Tariffs and Rates

Jan Macpherson, Office of General Counsel

Mike Henry, Office of General Counsel

Panel 1

David Cory - PacifiCorp

Steven R. Herling - PJM

Kevin Mankouski - ISO New England

Paul D. Olivier - Entergy

Phil Pettingill - California ISO

Bruce Rew - Southwest Power Pool

Panel 2

James Caldwell - American Wind Energy Association

J. Jolly Hayden - Calpine

John Jimison - U.S. Combined Heat and Power Association

Panel 2 (Continued):

Donald Jones - Xcel

Donna Reed - American Forest & Paper Association

John Simpson - Reliant

Justin Thompson - Pinnacle West

Weston L. Williams - Southern California Edison

Panel 3

John P. Buechler - New York ISO

Scott M. Helyer - Tenaska

Sam Jones - ERCOT

Pete Landrieu - Edison Electric Institute

Beth Soholt - Wind on the Wires

Lou Ann Westerfield - Idaho Public Utilities Commission

Kim Wissman - Ohio Public Utilities Commission

P R O C E E D I N G S

(10:00 a.m.)

MR. ROONEY: I'd like to be able to get started as soon as possible, so if people could take their seats, please.

(Pause.)

MR. ROONEY: First of all, I would like to say good morning and thank you all for coming. I'm Pat Rooney. I'm with the Office of Markets, Tariffs, and Rates. Today I have with me Mark Hegerle, Roland Wentworth, Bruce Poole, Norma McOmber from OMTR, Jan Macpherson who will join us in a few moments I guess, and then Mike Henry of the Office of General Counsel. There's Jan. Okay.

The purpose of today's conference is to explore significant queuing issues that have been raised during small and large generator interconnection proceedings and the SMD proceedings. For example, small generators have argued that they should not be in the same queue or undergo the same interconnection studies and processes as large generators because they little or no impact on transmission providers distribution or transmission systems.

They also contend that many of the small generator projects have limited operating margins and unless study cost and interconnection processing requirements are eliminated, or at least minimized, they won't not be able to compete with the larger generators. Transmission providers and others, on the other hand, have argued that any generator, regardless of size, can have an adverse effect on system safety and reliability.

In all three proceedings, concerns been raised that in certain circumstances, queuing can have a detrimental impact on competition, particularly where a transmission provider who also owns generating facilities uses the queuing process to create delays in getting new interconnections on line.

Also raised in all of the proceedings are concerns about how to deal with debt or inactive projects that could impede the interconnection of lower queue generators.

Today we're going to talk about the current status of generator interconnection queues, examples of good and bad experiences associated with the administration of those queues and what queuing policies and practices need to be changed to improve the queuing process itself.

First, I'd like to get started by going over a few details related to the organization and format of today's conference. Many people have asked that they be allowed to be on the panels, the three panels today. However, we were only able to accommodate a few. That being said, we would like to have as much input from as many people as possible on these issues and strongly encourage everyone who has not submitted comments to do so. We ask that the comments not exceed 20 pages, however, and that they be filed no later than February 4th.

We plan to work through each of the issues for the three panels so that we can get a better sense of the queuing implications and fill in the gaps in the record. The Commission will use the results of today's conference to ensure that the queuing policies in all three rulemakings are consistent.

As I stated earlier, there are going to be three panels. Each panelist will have five minutes for their opening remarks, and to ensure that we get everything done today, I ask that each panelist stay within that five-minute time period. Once the opening remarks are completed, the panels will be available for questions from the staff here at the table. However, there will be time set aside for public comments at the very last panel.

I will ask each of the panelists to please introduce themselves and say who they are affiliated with when they begin their opening remarks. Norma or anybody have any comments?

MS. McOMBER: Just a couple of other things. Welcome to all the panelists, thank you very much for joining us here today. We are broadcasting this conference over the Internet, so whenever anyone speaks, please make sure that your microphone is on so that the broadcast will capture your comments. It's also being videotaped.

The second thing that I wanted to add is that copies of all the materials that the panelists prepared will be available on the Internet later on today at the ferc.gov Web site. So if there are any panelists here that have not submitted material, if you could please make sure you e-mail those to me, I'll make sure that they go on the Internet.

The third thing is that there is going to be a transcript made of this meeting so any comments that flow from our discussions after your prepared remarks will be captured by the transcriber today. They will be available immediately after the meeting for a fee through our stenography service, our transcription service excuse me, and they will be available through FERIS a few days afterward if you would like to download them at that point. Thank you.

MR. ROONEY: David, why don't we start with you.

MR. CORY: I'm Dave Cory, PacificCorp. I'm Director of Transmission Services and I've been in that position since approximately 1990. I'd like to give just a short overview of what I feel the assessment of our queue administration has been, especially over these last two years with all the interest in interconnections of generation.

I think overall, I think our customers have been satisfied. I know of no complaints. Problems have arisen I think specifically with wind projects and the problems that I've experienced is this continued rollover of the tax credit. It puts the wind developers into where they have just a one-year window and typically they don't get started until like June, and then they've got to have the projects on line in December. I think it would be a real benefit if they would put like a five-year window on that or some extended period of time so some proper planning could take place both from the developer and from the transmission provider.

As far as PacificCorp we serve transmission services across the six northwest states and effectively are a mini-RTO. Our other big transmission provider, Bonneville Power, I've compared notes with them and our activities of independent power producers requesting interconnections have been very similar. During the period of 2000 to 2002 collectively, we've had a request, 94 requests bringing about 20,000 megawatts proposed to be on line. And as of December 13th of 2002, we have about 6700 megawatts remaining in our queue, and we have completed approximately ten projects with about 1500 megawatts of capacity added to the system, and what we've seen is, over the last two years, the interest in interconnections is totally dependent on the market and the second deterrent is transmission availability.

PacificCorp has a lot of transmission but it's highly used and we have little transmission capacity available to satisfy new transmission services. PacificCorp's practices for processing the queue for generation interconnections is show in Exhibit A and basically what it is that numerous milestones in the process. And if the milestones both for the requester and the provider, if the milestones are not met by the requester, that could be, we can then deem that their request application is withdrawn and they're removed from the queue. But it's our decision. We have the latitude to continue with them if they make some good, reasonable request to extend it.

We do not provide any financial transmission rights or any property rights through our generation interconnection agreement and one of the issues I've heard discussed is the concern about gaming of requesters getting hit with network improvements and then pulling out so the next guy that's in line for that same spot gets caught up with that.

I think, personally, that with the interconnection customer getting credit on his transmission bill for the network improvements end up will be transparent and is not a hindrance and is a deterrent to gaming.

PacificCorp has two separate queues, one for the generation interconnection agreement and one for transmission services. There is no relationship between either one. Our study procedures and interconnection study have no comparison to the transmission study. Our interconnection study is very simple and I've said in all our requests for interconnection, we've met the deadlines we've indicated would take us to get it done.

And with that I see my five minutes is done. Thank you.

MR. ROONEY: Thank you.

MR. HERLING: Good morning, my name is Steve Herling. I'm the Executive Director of System Planning with PJM. I'll talk quickly about some of the principals underlying our generation interconnection process. Obviously the goal of the process is to get generation connected to the system, first to ensure the adequacy of the system moving forward but also to facilitate robust competitive markets. And obviously we'd like to get generation built in the right place from an operability standpoint.

The process is designed to continually ensure that we have a reliable transmission system at every point in the process. The plan to accommodate the projects in the queue has to represent a reliable system, one that is compliant with reliability criteria. Transmission capability is obviously a finite commodity. The process has to balance the rights of a lot of different transmission customers. It's network service customers, point-to-point customers, generation interconnection customers, and soon merchant transmission interconnection customers.

But it also has to give the customers the certainty that their rights are being preserved every step of the way. To make that happen, our process is based on a series of milestones and our ability to manage those milestones and the compliance of the parties in the queue with those milestones to ensure that everybody's rights are preserved and that the process moves forward in an orderly fashion.

Obviously our philosophy here is that this has to be fully integrated into all aspects of system planning. We're dealing with the transmission system, all the pieces have to fit together. Generation interconnection, all of our other planning for baseline needs, merchant transmission moving forward.

I'm going to hit very quickly to basic issues; the need for enforceable milestones in the process and the use of queue windows to evaluate projects. The whole point of a queuing process is to enable good projects to move forward, to get them built, to get them connected to the system and into the markets. In order to do that, you have to have a process that weeds out the bad projects. Again, transmission's a finite commodity and you have a lot of people competing for it so you've got to separate the wheat from the chaff.

The queuing process has a lot of progressively more significant milestones, through feasibility studies, impact studies, facility studies, and even once interconnection service agreements are signed, any project that remains in the queue we are holding out a certain amount of transmission capability for that project. If the project is moving forward, then we should preserve those rights and allow that project to continue to hold that capability. If the project's not moving forward, we have to get it out of the way, get the projects that are moving forward connected to the system utilizing the transmission capability efficiently.

Essentially the milestones are there to minimize gaming. It allows everybody the opportunity to get their projects in the queue, get them studied, and as long as they continue to meet milestones, we will continue to study their projects and preserve the rights that they have. But they have to meet more progressively significant milestones every step of the way for us to continue to hold those queue positions and obviously if they are willing to put up that money, then we are willing to keep studying the projects. But the point of the milestones becoming more significant is to minimize that level of gaming.

The queue windows, the whole point of the queue windows in the PJM process are for efficient processing of the requests. We have processed now probably 300 some odd requests. The analysis cycle is defined as a six-month cycle. All the projects that come in we evaluate them in a combination of sequential and clustered analysis. When we get done with impact studies, for example, everyone is making decisions based on the same amount of information about their responsibilities and everyone else's responsibilities about their knowledge or lack of knowledge of which projects are going to move forward and which projects are not going to move forward.

We don't have a problem where, you know, a number of projects coming in week after week after week essentially make it impossible to complete studies and get viable results back because you're continually resetting your baseline. And that's the whole point of the queuing windows is you start with a baseline, you have the best available information at that point in time and then you study a group of projects. They make their decisions and then you move on with the next group of projects with the best available information, you set a new baseline and you study those.

And the last thing I'll say is there's absolutely nothing about the queuing process that makes it impossible for us to expedite small projects or energy-only projects. We do that now. There is the opportunity for expedition. Queuing and windows should not be viewed as an impediment to expedition for small projects. Thank you.

MR. ROONEY: Thank you. Kevin?

MR. MANKOUSKI: My name is Kevin Mankouski, I'm with ISO New England. I'm a lead engineer and I've managed the interconnection process within the NEPOOL system since 1999.

In New England, our study process also addresses the transmission owner's system tariffs which cover upgrades that are not NEPOOL to the non-NEPOOL system. If a project looks like it has a balance of non-NEPOOL system upgrades and local transmission provider upgrades, we enter a process jointly with that transmission owner.

If a majority of the upgrades will be on the bulk transmission or NEPOOL transmission system, it's that ISO study transmission owner systems are treated more as third party impacts in the study process covered under the ISO Study Agreement.

We've had a queue since mid-1997 with the advent of the open access tariff in New England. An issue arose with the style of interconnection for units where we looked for fully integrated interconnect similar to units of the past in the NEPOOL system which resulted in the Bucksport Order and the development of NEPOOL's minimum interconnection standard.

A point I'd like to make is our study too is a one-stop-shopping process. Any generator that wants to produce power regardless of their size is welcome to enter into our queue. Any project which wishes to sell into the NEPOOL market is required to enter our queue whether it will interconnect to the distribution system or not. We do this to really protect the generator to coordinate other competing projects which may wish to interconnect to the local distribution system in the immediate area.

If projects on the distribution system wish to sell to the local transmission company through contracts with the local company, we do not require them to enter in our process.

Our queue covers point-to-point transmission service, it covers merchant transmission in really requests for interconnection of generators regardless of size, regardless of whether they're connecting to the NEPOOL or non-NEPOOL system.

I believe we've had a very successful program in

New England. The early part of this year we expect over 10,000 megawatts to be interconnected to our system. We have yet another 2,000 plus that have completed studies but are still in our process where they are either developing interconnect agreements or working closely with the utilities to move them through that process and file unexecuted interconnection agreements.

We also have in our queue the option for any market player to ask for what we call elective transmission expansion. And a generator can take advantage of that as a separate queue request should their minimum interconnect generator upgrades not alleviate the congestion that they wish to overcome to play in our market.

I'd like to point out that our process is very flexible. We're very study intensive. The NEPOOL system is a heavily networked congested system. Transfers on the high voltage 345kV system affect the lower voltage systems. It's an old system and sited in old parts of the country where expansion of the lower voltage system is usually very difficult and problematic.

We have a subordinate study process. This relates to the fact we have a series queue so projects going forward are allowed to not assume earlier queued projects will proceed. However, should those earlier projects to proceed, they later queued process has to readdress that project in its study.

We have an expedited interconnect process after the system impact studies are completed and there is where we're working in conjunction with the local transmission owners and providers.

MR. ROONEY: Okay, thank you. Paul?

MR. OLIVIER: Good morning. My name is Paul Olivier for Entergy Services. Entergy is very familiar with the challenges of managing a large and rapidly growing queue.

Since January of '98, Entergy has received over 182 -- or, I should say, 182 interconnection study requests. Our queue backlog once reached a peak of 52 studies in November of 1999, but we reduced that to a mere handful today.

Despite such a taxing demand, our process has worked very well. The graph on the second slide of our presentation indicates that for now, the wave seems to have passed.

The remaining active studies represent a potential of over 38,000 megawatts to the Entergy grid, an increase of 165 percent to the original native load. Nearly 26,000 megawatts have already signed interconnection agreements, and of that number, over 12,000 megawatts have already completed construction.

At Entergy, a generator's queue position is established by the date a completed interconnection study request is received. Small and large generators, QFs and ITPs, affiliates and non-affiliates are all put into the same queue.

To obtain a position in the study queue, generators must provide certain basic information such as the configuration of the generator facility, where it will connect to the grid, and certain technical characteristics of their units and transformers, so stability and short-circuit studies can be performed.

The Entergy Transmission Business Unit maintains this information as confidential, until the customer files an IOA with the FERC. To ensure the integrity of the queue, Entergy has not allowed significant changes to be made to an interconnection study request after it has been made.

If a party desires to make a significant change to the project, they can submit a supplemental study at the end of the queue, or they can cancel the original study and resubmit a study at the end of the queue.

Entergy has allowed parties to assign their study queue position to other parties, provided the basic parameter of the study stay the same.

Entergy does not require external milestones such as site control, however, we do require internal milestones such as adherence to the interconnection study process and certain commitments to financial authorization required there.

No event triggers a change in queue position. A project is either cancelled or it's active, and it's only canceled if the customer requests that it be cancelled, or if they fail to meet these internal milestones.

There's no difference between the way Entergy resources or network or capacity resources are studied for queuing purposes, and although small and large generators are in the same queue, some small generators do not require the same level of stability study as some large generators.

However, we do feel that 20 megawatts can sometimes be too large to be considered a small generator.

The depth of the study that's required depends on the project location and other factors. Entergy believes that sequential processing of study applications is efficient.

Generators that have filed interconnection agreements are included in our model; generators that have not filed interconnection agreements but have only applied for studies are not included in the study model.

Entergy prefers this method so that it can meaningful study multiple project locations for basically a single project for a customer. Queue position for us only governs the order in which a study is done; it does not imply responsibility for upgrade costs.

Therefore, interconnection study queue position does not determine entitlements to financial transmission rights or other property rights. These rights and obligations are tied to a signed and/or filed interconnection agreement.

Costs for upgrades are assigned to the interconnecting party that causes the need for the upgrade, and as determined by the timing of the signing or filing of the interconnection agreement.

If a party with a filed IOA cancels, generators that sign subsequent to them are restudied and will be responsible for any incremental costs or benefits that result from the cancellation.

However, of the nine projects that have cancelled after signing IOAs, none have yet resulted in incremental or decremental cost responsibilities to subsequently signing generators.

Sequential assignment of cost is equitable. There is a perception that cost sharing results in lower costs, but this is simply not true in all cases.

Cost allocation does require batch processing or queue windows, but we believe that this adds an unnecessary delay in the process, especially when applications are dropping off, and it does create additional administrative issues and financial security issues if people cancel and drop out of the process.

Entergy maintains separate and distinct queues for interconnection and transmission service. This is done for several reasons:

First, interconnection studies require information about machine impedance and focus on the stability and fall currents. On the other hand, transmission service studies require information about the location of the receiving loads, and focus on load flows.

Second, most generators do not know where the ultimate load will be at the time they file their initial interconnection study request.

Finally, transmission service studies are done for existing transmission customers, markets in other states, for example, that may not even be part of the interconnection process.

So that's why we maintain two separate queues. There are separate issues, separate focus, separate results, and separate sets of customers.

And that summarizes the state of queuing at Entergy today.

MR. ROONEY: Thank you, Paul.

MR. PETTINGILL: Good morning. I'm Phil Pettingill; I'm the Manager of Policy Development at California ISO. I want to thank the Commission and the Staff for the opportunity to participate today in the conference.

And what I'd like to do with my initial comments here is to walk you through the slides that we have prepared. We're going to give you a significant amount of information on the boom-and-bust cycle of what's happened in California.

I'm then going to touch briefly on Rule 21. You've asked for details on how interconnections are handled. This important point about Rule 21 is that it deals with interconnections to the distribution system.

And then, finally, there are ISO's recommendations for some key characteristics that we might consider in the queue.

So we take a look at the first slide, and what you'll see is a significant response to California's electric crisis, beginning in 2000 where we had a significant and rapid growth in completed projects.

This culminated in what we see going forward into year 2004, with over 11,500 megawatts of resources that are expected to connect to the system.

On the other hand, if we look at the next slide here, California experience in terms of cancelled projects, and we take a look at this picture, you can see a surge of cancelled projects since 2001, and this has to do with the energy prices, and, of course, other circumstances that we have seen in California.

The key point I would show you here is, again, looking at year 2004, you can see over 12,000 megawatts of projects that have now officially cancelled and dropped out of the queue.

What this means for queue administration is that there's a significant surge in terms of increase, and then when the projects drop off, there's this need to restudy and to recalculate what the impacts are for the subsequent projects in the queue.

However, I'd like to emphasize that because of the sequential queuing process we use, we think we've been able to complete a number of projects and get them connected to the grid. And that is, of course, the perspective that we have; that the primary purpose of the queue is to get generators connected to the grid.

If we look at the third slide on California Rule 21, I think the important message here is that this is a rule that was created by the California Public Utilities Commission. It has significant stakeholder input; it's been in place now for over two years; and you can see some of the key elements here that it is a transparent process.

Generators understand what the technical screens are that will be applied to them; it is size-neutral, and it focuses on an ongoing review and improvement of that rule to make sure that the stakeholders continue to have an input in determining how effective it is for helping generators connect to the distribution system.

And, finally, I'd like to focus on some recommendations that the ISO has in regards to queue characteristics: The primary purpose of the queue is to get generators connected to the grid in a non-discriminatory manner.

And so what we have seen in our experience is that it's important to have a complete application, so that generators that come and submit have thought through where they want to connect, what the technical characteristics of their project are, and they are willing to place an initial deposit to cover those primary study costs up front, so that they, once they hold a position of the queue, they're not affecting subsequent generators that come in after them.

Milestones are important to ensure project progress, so that, again, subsequent projects are not affected because a generator ahead of them are holding up their progress, and, again, the point here is to balance the expectations of what the generators are trying to accomplish, but as well as what we are as the ISO and the transmission owners on managing the transmission network.

Property rights, we think, are an important element in terms of queue position and holding the queue position. It's an opportunity to develop an incentive for generators to come to the queue.

If they go ahead and put the time and money and resources up front to establish the queue position, should they choose to drop out of the project, they should be allowed to do so, but we would suggest that there is a need to manage that the technical requirements do not significantly change in that project because, again, it may necessitate a significant amount of restudy and affect later projects in the queue.

Regional variation is a significant element to considering queues. In California, we do have land control requirements, but the California ISO does not institute those requirements. We defer to the California Energy Commission that actually does the permit and siting of all generator projects, and allow them to apply things like land control.

As a result, it's still an element, but not directly as part of the Cal ISO, so regional variation is a valuable element to understand.

And, finally, I guess what I'd like to point out is the last two bullets. Independent queue management is an essential element here. We're trying to balance the interests of generators, as well as transmission owners, and trying to ensure reliability on the system.

And as a result it's important to apply best efforts to get generators connected to that system. In terms of integrated planning, then, we look forward to what's been described in the SMD where there's a single entity that has the integrated regional plan, and what we would see as the queue, becomes essentially a subset of that integrated plan and focuses then on how generators that have similar milestones and financial requirements are treated equally under that same listing or queue, if you will. That's my comments, thank you.

MR. REW: Good morning. I'm Bruce Rew, Manager of Coordinated Planning with Southwest Power Pool. Thank you for the opportunity to discuss the generation interconnection queues of the both the Midwest ISO and Southwest Power Pool.

The two companies are the process of merging, and I'll discuss our experiences from both queues and what we're working towards in the combination.

First, both of our queues are first-come/first-serve queues. We do have a significant number of requests that we're dealing with. Because of our large geographic area, we are able to break it up into subregions, which allows us to study multiple requests at the same time.

The RTO is a central point for coordination of all the interconnection studies. All the requests are made through the RTO, and we work with the transmission owners after that point.

We have several areas where significant competition exists in generation. These are favorable areas for generation, and that has created a backlog in certain areas in processing the generation requests. We do recognize both small and large generation interconnection requests.

Right now, we're working on 20 megawatts, which is where our breakpoint is for small generation, if there is no significant impact on other requests and we're able to expedite processing of those small requests.

We do have milestones. Our milestones are primarily internal milestones, internal to the study process. We do require siting for the generation interconnection. We also work with affected adjacent systems, and that has added to our processing time, but has improved the overall results of the study and the interconnection.

Our cost responsibility is based on the queue position. As I said, we have a first-come/first-served serial process that we work through, and that's how we allocate the costs.

We do not recognize energy or network resources. All of our generation interconnection requests are treated the same, and we do look at the ability to have optional upgrades as part of that process.

There is no transmission service interconnection processing. Those are completely separate, and actually we've seen generators interconnect to our transmission grid without any transmission service. They have strictly operated in the short term, and then, likewise, we do have the opposite where generators have long-term service committed and are fully integrated network resources.

The generation interconnection queues are a significant part of our transmission expansion planning effort. We have looked at different generation scenarios in the transmission expansion plan.

We do use a pro forma interconnection operating agreement, and that has helped facilitate the interconnection agreement, and that's an important part.

A couple of things to mention: We have seen in a couple of places where RFPs have created numerous requests in the queue, and that has added to the backlog of processing requests. We do limit the modifications to the request, and that has helped reduce the processing time required.

And currently we're investigating development of an aggregate study called the Cluster Study in the NOPR. We see significant benefit in doing that: The ability to group requests together to expedite processing; the ability to optimize planing, and reducing the overall cost of interconnections for multiple generators, as well as the ability to have cost-sharing for the generation interconnections.

We also see the need for the transition provision to make sure that the processing of requests continues, especially for any interconnection existing process that doesn't have milestones.

And third-party involvement is definitely a significant part of the interconnection. We have a lot of seams issues, and we're working on seams agreements, and those will resolve the majority of the processing part of it, the engineering, but there will be other issues that would need to be resolved.

And then we'd like to make sure that the interconnection operating agreement is compatible for all types of generators. In our area, we're seeing a wide variety of generation, from wind to gas to coal, and these generators have different operating requirements, and we'd like to make sure the IOA is compatible for all types of generation. We thank you for your time this morning.

MR. ROONEY: Thank you, Chris. I do have one question. One of the things that we have indicated, at least when I first started talking, was the concerns about dead or inactive projects.

And one thing that I have noticed is that it appears that both the ISO New England and the MISO, appear to have a number of inactive -- a significant number of inactive projects, more so than the rest.

And I was curious as to why that's occurred, and also what you intend to do about that.

MR. MANKOUSKI: I'll answer that. We reported the inactive as withdrawn projects. You're either in a queue or out of our queue.

I guess the best way to put it is, in the management of our process, we put our emphasis on projects that need the work most to get successfully interconnected.

Again, we have like over 2,000 projects that are more in the hands of our transmission owners, because they are the ones that are responsible to develop the interconnection agreements.

So if the projects truly aren't interested in proceeding, we need to have, I guess, a more standardized interconnection process.

I'll add that interconnection agreements should also have milestones for projects.

MR. REW: For the Midwest ISO, our definition of inactive is that the request was made and it did not go through to a completed state and it was withdrawn for various reasons.

MR. POOLE: I guess I've got a followup question on the same subject. If I take MISO and SPP and I look at them, if I counted these right, I saw like 46 in the total of the queues, and 35 of them were inactive or they had listed "no" on the sheet.

Are they not being worked with anybody? Are they not in the queue?

MR. REW: That's correct; if they are listed as inactive, they are not in the queue. They have either withdrawn or didn't make their milestone requirement, and they're no longer an inactive part of the queue.

MR. POOLE: I mean, 35 out of 46 seems like a large percentage. I guess my question is, did they withdraw, did most of them withdraw, or are they just missing milestones?

MR. REW: I'd probably say that the majority have withdrawn, but there have been some that have missed milestones.

MR. POOLE: When they withdraw, where along in the process do they normally drop out? I mean, is it early or is it late?

MR. REW: Most of the withdrawals would be after they have received some study results.

MR. POOLE: Okay, like a feasibility study?

MR. REW: Yes.

MR. POOLE: Okay.

MR. HERLING: I think that generally, we're all -- maybe the inactive term confused us, but we don't have inactive projects; we have projects that are still in the queue and we have projects that have been withdrawn.

Our experience is that the vast majority of projects do not contact us and tell us that they are withdrawing; they simply let a milestone pass; they don't respond to a study within the required number of days, and then they are deemed to be withdrawn.

In our case, about a third withdraw at the end of the feasibility studies. It's up to a total of 50 percent at the end of the impact studies, and then the rest of two-thirds have withdrawn, either through the design studies or at the point where they have to sign an ISA.

So, in our case, we're looking at 102 projects that are still in the queue, approximately 68 completed, and that means another 150 or so have withdrawn.

MR. POOLE: I have another question. Mr. Olivier, I was looking at the Entergy queue, and it appears to me that if I'm reading this right, 88 percent of your projects dropped out after the feasibility study.

I'm just wondering, but that seems like an awfully high percentage. Is that because of the amount of projects or is that because of the difficulty of the feasibility study or what?

MR. OLIVIER: No, our feasibility study is actually quite streamlined. It's a very basic load flow.

I think maybe -- I can't speak to every case, but we created as system that tried to encourage generators to look at multiple sites. And that's why we call it a feasibility study.

They may have a single project in mind, but they may be considering multiple sites. So, we would do a feasibility study for four sites, and from the initial feasibility study, you get a rough idea of which area might be more or less constrained, transmission-wise, than another area, and that's the first step.

And as a result of that feasibility study, we do give them some very, very high-level, rough cut estimates of the cost of upgrades and such, so that they can evaluate Site A versus Site B versus Site C. They can eliminate three out of the four sites and move forward with their preferred site.

So that might be something to do with why there are so many that have cancelled after the feasibility stage.

MR. POOLE: And then these listings here of the 182 or something on the queue, would those be three sites for the same possible generator?

MR. OLIVIER: It varied. I'd say that the majority of the people had only one site.

MR. POOLE: Only one site?

MR. OLIVIER: Yes.

MR. POOLE: Okay, was it -- is it just the lack of ability to handle more megawatts on the system that's caused all of the facility studies to provide such a high dropout rate, or is it the lack of people to do the studies in a timely manner?

I'm just trying to figure out why it's so high.

MR. OLIVIER: I wouldn't know how to answer you, Mr. Poole.

MR. HEGERLE: I'm sure it varies from customer to customer. I was just looking at it from the other side, like all of you have, sort of diverse views. I'm thinking a little differently from Bruce, that in some ways, having a stringent test up front that pushes people out of the queue right away is a benefit to others in the queue.

MR. OLIVIER: We don't push anybody out.

MR. HEGERLE: I didn't mean that in a negative sense, but more in a sense that it cuts down on some speculation as far as siting and doesn't leave folks in the queue as long, further into the process, delaying and complicating --

MR. OLIVIER: I think that's right. We created the feasibility study stage as a service to customers, as a way to try to educate them as quickly as possible about the feasibility of the site that they have chosen. That's why we call it a feasibility study.

MR. ROONEY: Phil, go ahead.

MR. PETTINGILL: I just wanted to respond real quick, Mr. Poole, on your question about inactive projects. With California ISO, we don't have any inactive projects in the queue either.

However, my point about the CEC and the land control, we do have some projects that from time to time -- we call them suspended -- where they are in the queue, they have progressed a fairly significant way in terms of meeting the milestones, but because they have not completed the CEC approval, then we would hold them in suspension, meaning that once they complete the CEC process, we would re-queue them in with other projects that are a comparable stage in the queue.

So if they are at the point of having to show land control and permits, then we'll re-queue them with similar projects and then they are back in the queue and move forward with their peers.

MR. POOLE: While you were mentioning that, I had just another question. If I count these right, and if I look at the year 2003, in California, if I look there, as I see it, you have four different queues.

You've got one listed for the ISO, one for PG&E, one for San Diego Gas and Electric, and one for Southern California Edison. And I would count up 39 projects that are listed to come on in 2003. Do you think that number is going to be achieved?

MR. PETTINGILL: Probably not.

MR. POOLE: Okay.

MR. PETTINGILL: Given the cancellation rate. And that was the reason that I wanted to share with you --

MR. POOLE: But they are all listed as active.

MR. PETTINGILL: Yes.

MR. POOLE: Okay, okay. The majority of those, like, 26 out of 39, are in Southern California Edison. And a lot of them are small generators.

Is that mix going to be different? Why is that different from, say, the other parts of the state? Is that Rule 21? Or what causes that difference?

MR. PETTINGILL: What you're seeing in the queue there does not include generators that would be connecting under Rule 21, because those connections would be at the distribution level.

MR. POOLE: Okay, so this wouldn't list anything in Rule 21?

MR. PETTINGILL: Exactly. Just to give you an example, Edison's numbers would increase somewhere in the range of about 200 projects, if we added those Rule 21-type projects.

MR. POOLE: Okay, because there are a lot of them in here though that are like 24, 20, 19 megawatts that are listed here.

MR. PETTINGILL: Exactly.

MR. POOLE: And were those in here before Rule 21, or why the difference?

MR. PETTINGILL: I couldn't say. We'd probably need to ask Edison, who is going to be on another one of your later panels, and see if they could provide some detail.

I guess one observation I would share with you is, that's the significance of the 2004 data, looking forward in terms of interconnections, and where you see, you know, 11,500 megawatts connecting. Those are the larger projects.

I think what we saw was folks responding to the economics and the energy crisis, and it takes enough time to actually construct those projects that they're not coming on until 2004 for the larger megawatt projects.

MR. PETTIGREW: Then having the four different queues, then does the California Commission or somebody -- who's doing an overview? Is that their task?

MR. POOLE: That's a fair question. Where we're at is we're in transition. We had our Amendment 39 just authorized by the Commission in June of last year. And so the reason why you see the multiple queues listing there is we wanted to give you a fair characterization of how many projects are connecting to the transmission system.

We're in a transition to the ISO queue, and what we've done then is closed new applicants to the transmission owner queues, but we're going to allow them to go through, because they had in some cases differences in regards to their queue management. So it's a matter of just transitioning projects to the ISO.

MR. PETTIGREW: So all of these that are listed here would be hooking on transmission?

MR. POOLE: Yes.

MR. PETTIGREW: And there would be 200 or so more on distribution?

MR. POOLE: Absolutely.

MR. ROONEY: Steve, go ahead.

MR. HERLING: I'll just make a quick comment. We obviously have a different philosophy on the feasibility studies. We do a tremendous amount of analysis, and we require site control to get into the queue to get a feasibility study. Our concern obviously with allowing customers to come in and looking at a lot of sites without site control is we know they're basically using us as a consultant, which is okay I guess. But in order to manage the process, we have really determined that that's just not feasible for us. We have enough requests in the queue that bring us site control. We'd have ten times as many if we didn't require site control.

So we view the feasibility study -- I mean, we have a 30 percent, 33 percent dropout rate after the feasibility study even with site control. So my concern would be not requiring, we would have three, four, five times whatever, the number of requests.

Those services can be provided by the industry. There are consultants who can do these types of studies, help developers find sites. Many of the developers have their own engineering staff to find sites, do the preliminary analysis, weed them out, and then bring us one or two with site control and then we'll do the feasibility studies.

MR. ROONEY: All right. Thank you. Can the rest of you follow up on Steve's remarks? I'd just be curious to determine what you all's feelings about the multiple interconnection requests are and how you'd handle those. For example, PJM is saying we don't really want to deal with multiples. We want to make sure that they have -- well, they want to have site control in order to get into the interconnection queue. And I guess that's my question to the rest of you very briefly. Could you all respond to that? Kevin?

MR. MANKOUSKI: Yes. In New England, we have a site control requirement. We want a defined project when you come to our queue. We're flexible in that we will downsize a project if there are insurmountable interconnection costs as long as it's not -- well, the applicant is making the decisions in a fairly fast pace.

As far as feasibility, we will have informal meetings. I think most of the time it's getting details ont he configuration of the transmission equipment -- conductor sizes, whatever.

I've noticed that's a concern for the smaller projects, getting information on a distribution system, and in all cases if they come to the ISO, the distribution companies' engineers will informally meet, will teleconference. And of course we put a limit on that of what's reasonable. We don't want to serve as their consultant. But clearly, where the information isn't publicly available either in the FERC filings obviously distribution systems aren't there, or it's not available from the state, the consultant needs that basic information.

MR. ROONEY: David?

MR. CORY: PacifiCorp has had few experiences with multiple requests for the same point of interconnection, but we have in a particular case. And we handle -- put the projects in the queue when they've completed their application, and we serve them on a first come, first serve basis.

In the case where we had multiple requests, we did all the studies and provided the information to the entities. The entities also then followed up with transmission requests and because of the response or our response to the transmission requests is that the second and third project removed themselves from the queue.

MR. OLIVIER: At Energy, we do allow people to ask for a feasibility study before they have site control, but our feasibility study is limited in scope and it only looks a certain number of buses away, and it has some very simplifying assumptions that it will be either delivered to the North or to the West or to the East.

So we don't really have a problem with an overabundance of studies in the queue. We think it's important to arm the customer with as much information as he might find useful early on in the process.

Steve is right. They are using us to some degree as a consultant, but we have the information, and when we had such a backlog of studies in our queue, it's the detailed interconnection study that takes so long, the stability and short circuit. That takes quite a while.

So while we had that in the backlog, running simple load flows, which is what we do for feasibility, we were able to respond to those within 20 days in almost all cases. So it's not been a great burden for us.

MR. PETTINGILL: In the California ISO, we primarily encourage the generator to use consultants in order to do most of the feasibility efforts. In terms of submitting their application, they do need to identify at least a point of interconnection.

But I guess what I would do is point out that we also allow them to make a fairly significant change in the project fairly late. They can do the initial system impact study, but we do allow them to make a change in their project characteristics which may include the connection point, as late as after we've done the facility study, and they're now about ready to sign an interconnection agreement.

So we've given them an opportunity that after they've gone this far, if there needs to be a significant change, they can make that one last change and we'll go back and redo some of the study efforts.

MR. REW: In general, I agree with Steve that site control is a key part, and that's certainly required early on in our process. We do not want to be used as a consulting firm to evaluate the studies. We're not staffed for that.

In addition to that, by having the customers do their homework before they come to us, it does reduce the number of requests, and we know that the requests that are in the queue have already been evaluated, and it should proceed or have a greater likelihood of proceeding to an interconnection. Thank you.

MR. HEGERLE: Bruce, I'll just start with you and go backwards. To what extent is there information transparency so that customers or perspective interconnecting generators can look and find the information they need so that they don't use you as a consultant, so that they can come prepared? They're really saying I want to go and I want to go now. How can they do that?

MR. REW: Let me make sure I've got the question right. You're asking what the generators can do in order to prepare to interconnect, or to evaluate the interconnection?

MR. HEGERLE: Well, it seems to me as I listen t the responses that part of the problem is, if I'm going to be an interconnecting generator, I just don't know. You know, I can tell that obviously near a load center might be better than out in the sticks, but I can't tell where exactly should I get a site, where should I pursue it. Where is the backbone system strong enough that I could just jump right on, and that some measure of transparency would help that and would help speed the serous requests through the queue faster, if you had it.

I'm just wondering to what extent your company allows that.

MR. REW: As Steve has mentioned, there are many consultants available that will help in that area. We do make our power flow models available so that entities can request them and make an evaluation on the system.

There's a lot of other aspects involved with the interconnection outside of the electrical system: The fuel source, water supply, air permitting and all of the other aspects that go along with selecting a site. So it's certainly much more than just the state of the transmission grid, and we do make that information available through the release of our power flow models.

MR. PETTIGREW: For California ISO, we make our power flows available as well, and then we also encourage generators to go to our NERC coordinating council, the WECC. They give the whole systemwide power flow base cases available.

So, again, there is information that's readily available for them to know how to conduct the base studies and start to narrow down the site location.

MR. HEGERLE: So they could do it at home, so to speak?

MR. PETTIGREW: So to speak. I guess the other point I would share with you is we give them a significant amount of information on our Web site, and currently the transmission owners do as well so they understand what's necessary to complete the application in order to have a good complete application once they file it with us.

MR. OLIVIER: And like everybody else, we also make our load flow models available publicly. I get the perception that most customers do their homework before they come to us, even though our process does allow for some feasibility study, I think most do their homework with their own consultants before they come to us.

MR. MANKOUSKI: Although I pretty well responded, I'll add that ISO New England would like to have our transmission owners provide short circuit and stability data so consultants could use it and do feasibility studies.

MR. HEGERLE: You'd like them to?

MR. MANKOUSKI: Yes.

MR. HEGERLE: They don't now?

MR. MANKOUSKI: It's considered confidential information.

MR. HERLING: Along with the various data that's available to developers and their consultants, we have reasonably good documentation, and we've met on a number of occasions with developers and their consultants to review how we do the studies so that they can then go back and do these kinds of analyses.

So there's a lot of information available. They still have to do the work, but there's a lot of information available.

MR. CORY: At PacifiCorp, one doesn't have a requirement -- a prerequisite for site control. When we receive a request, we then offer, when they've completed the application, we then offer up to one day meeting with us with the appropriate engineering staff on board to meet with them and to review their request.

We understand in some cases the developer has some concept of where he wants to connect, but not specifically. And we will advise him at that time if he seems to be making a prudent request or not.

MR. HEGERLE: I guess I'll just go back this way again. Is that really the reason for delay? We hear from generators that, you know, I'm having trouble getting through the queue. It takes too long. I want to get on now.

From your position, what would you say is the reason for the delays that they face? Or is it there aren't any? I'm just trying to understand just from your side, the transmission side, why some generators would feel like it takes too long to get through.

MR. CORY: Well, if you look at our exhibit and you walk through it and if you took the end of the milestone for each case, it does kind of get extended. But for the most part, we try to respond as quickly as we can, depending upon the resources we have available.

And on the other hand, the interconnection customer, if he doesn't respond in a timely fashion, the milestone allows for a collection of time through the whole process to get rather extended.

MR. HEGERLE: Sure. If he's sitting on his hands and not serious, he's not going to get through. That's right. You mentioned resources. Is it resources on the transmission provider's side that tend to slow it down? Where is the hold up I guess I'm trying to figure out.

MR. CORY: Resources are limited on the transmission provider side. And you've got to realize that we were not created or staffed to be in a consulting business which we've been placed into.

But I would say that we've met -- we give an estimate of the time it's going to take us to complete, and for the most part, we've always met that or beat it. So I guess that's my response.

MR. HEGERLE: But again, as far as staffing, the interconnecting customer has to pay the costs of the studies, right?

MR. CORY: That's correct.

MR. HEGERLE: And if that was the problem, couldn't more staff be added and the fees adjusted accordingly to help that through?

MR. CORY: I'm sorry that I smiled. But what I really go back to is, is that in the period of -- in a very narrow period from say the summer of 2000 to the summer -- I'm sorry -- 2001 to 2002, we got 94 requests.

You know, it's dependent upon the market. And when you all of a sudden get that kind of surge, you've only got so many resources.

MR. HEGERLE: Sure.

MR. CORY: And the other thing is, there isn't that many consultants that we can go out and contract it out to, because that's not a very efficient manner in getting the job done either.

MR. HERLING: There are a lot of reasons why the process drags at times. We put a lot of staff on at PJM. At times we have been behind that curve, and it's hurt us a little bit. And then we have tried to use consultants to the best of our ability.

But staffing I don't think is the primary problem. You've got to remember, this is a business. The generators are trying to get their projects built. We send out -- I made the comment before. We send out reports, and invariably, if a generator is dropping out on the 30th day, we just don't hear from them. They don't call us up two days after and say, we decided to drop the project. They're hoping to either sell the project or for something to happen to keep it alive.

Human nature. We have a queue ending and we get 25 requests within a 5-day period. We scramble to do what we can to service those requests. Projects that are already through all the design phase and in construction are trying desperately to keep their project alive or sell the project, and then suddenly they drop out, and we have to go back and readjust so that the plan remains a reliable system for everyone, everyone else's rights are preserved.

This is a tremendous amount of work. But you have to give people good engineering answers.

MR. HEGERLE: Right.

MR. HERLING: You have to preserve their rights, and that means everything that happens, you have to be in a position to react to, and that just takes time.

There's a lot of decisionmaking going on by a lot of parties and it all has to be factored in. And everybody would like the process to move faster. But simply eliminating huge pieces of it isn't going to make that happen and get good results out to the customers.

MR. HEGERLE: Thank you.

MR. MANKOUSKI: I'll add that in New England when we had the rush of the projects, we had projects under construction and their studies weren't completed, their interconnection designs weren't completed. Again, we had very problematic interconnection issues. Short circuit is very difficult in New England.

We had a 1,600 megawatt plant in the Greater Boston area. We must have looked at 40 different interconnection designs to try to minimize the cost to the customer and allow the plant to be integrated such that it could export power out of the area that never was really designed to export power.

We were flexible. In special cases, we do work in concert with consultants. And again, flexibility is the key. We allowed a developer to actually contract. Consultants work in parallel with the actual ISO system impact study, and in a few cases we have under confidentiality agreements provided stability data to such consultants, because again, the project was under construction, and we still had to resolve interconnection issues.

I'd say resources are a factor. But again, within ISO New England, our process is a series queue. We have the subordinate process. We've had a few projects that their final study is the third time around for them because they have to remove their subordinate status. They were later in the queue, began construction soon after they applied to the queue and completed studies with earlier queued projects not considered.

We require that. If a later queued project comes online, it has to have a study to show it has no adverse impact without the earlier projects, because the earlier projects upgrades aren't on the system yet. And then as those earlier project upgrades are added, the later queued project needs to address those earlier upgrades addition to the system on their project: Do they still meet the minimum interconnection standard?

So again, our subordinate process is very study-intensive. We also have to coordinate these studies with the reliability and economic upgrades that are being added to the system. Throwing more people at it really isn't going to help, because you have to coordinate with all the ongoing studies, and that's very difficult as you throw on more and more consultants.

MR. OLIVIER: I think some of the comments it takes too long to get on the queue are probably well-founded. But I think it's mostly due to the fact that all the transmission providers have such a large crush, inrush of applications at one time, and to treat people comparably and fairly, you have to kind of start setting some protocols for how you handle each application.

We've caught up to our backlog and I don't think it would take nearly as long today as it might have taken back during the peak in '99. Also I feel the need to clarify one thing. When I say we do sequential processing of applications, I don't mean to say that we study one before you even begin another. We have hired consultants to try to relieve the backlog. We've hired up to four. We send out study requests to all four as soon as we can, but these studies still take time. And as the demand slacks off, we will probably not need to hire as many consultants and we'll go back to doing the studies in-house again.

MR. PETTINGILL: I guess I would underscore a couple of points that Paul made. We do try to bring in consultants and use consultants to help facilitate the process. There is a significant surge that we had over the last few years and even though in Cal ISO we do sequential again, where there may be a number of the projects in the queue that are being studied simultaneous.

I would like to point out also that milestones inherently protect the other projects later in the queue so we know that the projects ahead of them are progressing and are viable, realistic projects. But inherently they also create length, and so there is the need to recognize it if a particular study is supposed to be done in 20 or 30 days, then it is going to be usually 20 or 30 days until that study is completed. Sometimes it'll be completed a little less but clearly the milestones do create an inherent schedule and that sometimes has the perception of creating extra length.

With the surge, there's staffing limitations without a doubt, and I think what we've done in Cal ISO is allow for the use of consultants to do some of the major studies and that way we try to compensate for the fact that project overload can occur. We go out to consultants and try to bring them in to help with that.

The other thing I guess I would share with you also is the fact that while we generally use a sequential queue, we look for opportunities to bring projects together into a cluster or a batch, if you will, because there are a number of projects that came in almost at the same time. They're connecting in the same transmission constrained pocket, and if that's the case then we'll cluster them up and to those projects together to try to facilitate speed in that process.

MR. REW: I think in general our comments would be pretty much the same that it doesn't take very long to make a request but it takes a lot longer to process the request and certainly the engineering required to do a good job and making sure that everything is considered for the interconnection does take a while to do. And you know that has extended the processing of the queue.

MR. POOLE: Just a quick question. I noticed in several of the queues, say three-quarters of the way down the queue there were some large wind projects, maybe 2000-3000 megawatts. Do those take a different analysis approach or do you have to work them differently than you do say other generation sources?

MR. HERLING: I'll jump in. We haven't had any wind projects nearly that size. I think we've had some up around 100 megawatts. You know, a small wind farm has different analysis because typically they're energy projects and they're small. We can do certain analyses very quickly and others are not even required.

A very large wind project, if it's going to be injecting 1000 megawatts at a point on your system, the analysis is going to be largely the same as any other 1000 megawatt project. You have to design the transmission to accommodate that 1000 megawatt injection.

So once you get to a project that large, it's not a function of whether it's wind or not. It's just the injection itself. The smaller projects, there's a lot you can do to expedite those requests in the analyses. But anything that big is going to have a big impact on your system.

MR. REW: We have received several requests for wind in the southwest part of the Midwest ISO and if you look at the study process, it's the same process. They are studied a little bit differently once you look at the details of the engineering, the requirements, operational issues with the wind, and certainly one thing to remember, a lot of the wind generation requests we get are in remote areas. As I heard one say the best place to put wind is where nobody lives. And that also means that there's very little transmission there. So we face some other issues looking at the transmission required to interconnect reliably.

MR. PETTINGILL: I guess I would sort of parallel again what Steve's saying that it really depends on the size of the project because what we're looking for is the impact to the transmission system. It's not that there's a difference in how they're handled because of the technology, wind versus gas-fired or so forth; it's a matter of the impact. So if it's a small project, it can be expedited.

If it's a larger project, it's going to cause greater impact on the system and we're going to need to do the additional studies.

MR. CORY: PacificCorp has transmission that transverses a lot of great wind resources and we are maturing with such type generation and when I say is that one of the problems is that the vendors of the one-turbines don't provide the generation models. And that has created a problem for us and we've learned that it's extremely important. We think we've facilitated, through our revised interconnection study, that that not be a problem but it will be a definite consideration when we get the request for transmission service, then the generation modeling's going to have to be there and the results of these studies will have significant ramifications on the wind generation being able to deliver to the purchasers.

MR. OLIVIER: Entergy's had no request for wind generation but I agree with Phillip. It's the size and the characteristics of the machine and not what drives it; not whether it's steam, gas or wind that drives it.

MR. ROONEY: Are you done. Does someone else want to?

MR. MANKOUSKI: Well I'll add the thermal capacity loadings of the wind are not different than any other project but the dynamic stability performance is an issue and we have a large project and as part of our system impact study process, we have entered into agreements with consultants working with the manufacturer to develop those models the best we can in accordance with good engineering practice. And we're progressing along.

MR. HENRY: This is a question for Kevin of ISO New England. You mentioned briefly in your presentation that under certain circumstances the ISO New England will consider interconnection requests to the local distribution system. Would you mind explaining again under what circumstances you will and won't be considering interconnection requests to local distribution?

MR. MANKOUSKI: We always require application to our study queue for any project selling into the NEPOOL market. Any project that's typically under five megawatts does not sell into our market. They enter into agreements with the local company, energy agreements, whatever. But if they are selling in our market, we were involved in the study process. If it looks as though the bulk of the study work is distribution assessments, we enter into a two-party agreement under the tariff for that local distribution company system tariff because the majority of the upgrades are going to be under that tariff and not the NEPOOL tariff.

MR. ROONEY: Do any of the other panelists have experience with interconnection to local distribution?

MR. HERLING: Yes, but as Kevin said, it's really an issue of what the generator is intending to do. If they want to sell into the market, whether they connect at the distribution level or the bulk transmission, they have to go through the process. Now the analysis of distribution facilities, we're going to have to work, as Kevin said, with the transmission owner who owns those distribution facilities but they have to go through the tariff because their intention is to sell into the market.

MR. PETTINGILL: And for Cal ISO what we have is a wholesale distribution access tariff that the generators, if they want to sell wholesale, would be subject to. We, for some of the other reasons, the other panels mentioned, will defer to the transmission owner or the distribution company because they have the study data, the information on their distribution system and have them actually conduct the studies. But we ask and require them to give us the result of those studies so we can then determine what the impacts may be to the transmission system, so we coordinate with them to conduct the distribution impact.

MS. McOMBER: I'd like to go back, if I could, to affected systems and wind power that we were discussing right before this question. And my question comes up from something that Bruce said and something that David said.

Bruce, in your presentation, you talked about coordinating with affected systems, and so I would like to hear a little bit more about how you do that and to the degree that other people want to chime in and illustrate how they do that, I'd really like very much to hear that.

And then related to the wind power issues, you made a suggestion, David, about something that would help wind dealing with the tax credits that they have to apply for and the length of time that they have for that. I'd like to hear more about that, and if anybody else has -- I view these kind of as process observations that take time, and you may have some thoughts on how to improve them.

So to the degree that anybody has any other comments related to how to improve those two things, or if there's something else along those lines, I really would like to hear about that, please.

MR. REW: The coordination with affected systems, how that's determined is we make a look or we look at the interconnection request and we'll make an evaluation as to the proximity of a seam or a neighboring system, and if we determine that it will have impact, then we will get with the engineering staffs of those affected systems and get them involved in the study process through a study group, so they'll be intimately involved with the process and the details and make sure everybody's comfortable with the end result for the interconnection.

MR. CORY: Regarding wind, we have experienced like May or June of each year, all of a sudden a surge of requests for interconnection of wind and it's all because the tax credit's going to run out at the end of the year. And so we get these requests, puts a burden on our resources. We have responded in a timely fashion and then maybe a few do get connected and maybe they don't meet the deadline and lo and behold in December they extend it another year and all of a sudden it goes silent.

As I said, I guess in my mind, there are two answers to that. One, provide that tax credit to these for the wind projects for an extended period of time so that they can plan appropriately and the transmission provider can plan, or I guess the other answer probably isn't as encouraging to the wind developers; strike the tax credit for good. Either way allow for good planning.

MR. HERLING: I'll just echo a little bit of what David said. We've had wind projects in and out of our queue, the same project three times because they're racing the clock to get certain things done. They can't. They drop out of the process, and then they can't make any commitments to get back in the next year until they know that the tax credits are going to be in place so they wait and they wait and wait. They finally get in and then they're racing the clock again, and they can't get in place and they drop back out, and then we wait and we just do it again next year.

And I really feel for these guys but we're not really in a position to make things happen any faster. The window is just too short for them.

MR. HEGERLE: There was some discussion earlier about expediting projects, smaller projects and I don't know if this would be one of them. It doesn't sound like it might not be, and I know Steven you mentioned a couple of times you do that when you can. I was just going to ask all of you. What are the standards, to the extent you do expedite, what are your standards for doing it and how is it accomplished?

MR. CORY: PacifiCorp handles first come, first served, regardless of size. But we don't put in the queue anything less than a megawatt.

MR. HERLING: Generally, the ability to expedite requires a certain amount of judgment. We have to look at where the project is and how big it is and the likelihood of impacts on the system and on other projects. You know, with projects -- and we use ten megawatts as our threshold -- with projects under ten megawatts, typically we can move very quickly through a feasibility/impact study, identify the impacts and move right into design, even while the rest of the queue is still in the feasibility study phase. So it really is a matter of engineering judgment based on a quick look at where the project is, how big and what the impacts are going to be.

We've had other projects under ten megawatts that just based on where they're at, they have enormous impact on local distribution and you know all the wishing in the world isn't going to change that, and you just can't possibly expedite and do a good job with respect to the engineering design.

MR. HEGERLE: Does that mean as they get through phases in the queuing process, like you're saying, they jump ahead of others as they go? Is that the way you work it?

MR. HERLING: Essentially yes. If they're off by themselves, and there is no impact, we'll move them right to design and implementation while the rest of their queue is still in the feasibility study phase if that's the way it works out.

MR. HEGERLE: Thank you. David?

MR. MANKOUSKI: Yes, we can expedite a smaller project but again it depends where it's integrating to the system. We've had a case actually earlier than our queue in IPP that situated itself such that it preloaded a low capacity, low voltage transmission line, 69kV, such that it would degrade our import capability from New York by hundreds of megawatts. So of course you needed a study to identify mitigation so as to not adversely impact another case.

But again we have to assess all of those issues for the project to move ahead. But again, for small projects that are radial to the system and have no transfer capability impacts on the NEPOOL bulk system, there really are no issues there. It's entirely a distribution study and we take care of those in a very expedited fashion should they arise.

MS. MACPHERSON: Do you find an easy way to tell which projects are going to create a problem and which are not? Is there a way to identify right off the bat the ones that aren't going to create a problem?

MR. HEGERLE: Jan's going exactly where I'm going in the sense is there something we can write into our rules and we standardize things that would encourage this, or is it really all, as Steve was saying and I think Kevin you as well, that it's a judgment call.

MR. MANKOUSKI: It's an engineering judgment. A lot of these projects really offset local load so I think you have to throw in some quick assessments to convince the engineering community and NEPOOL that it has no affect and that's really the way we handle these. Again, most of them end up not entering our queue because they enter agreements with the local company to sell their energy.

MS. MACPHERSON: For all of you and anybody else, if there's anything you can give us in your further comments to identify, to help us identify projects that are not going to be a problem, we're looking for those kinds of ideas.

MR. HERLING: I'll just say there is no fool proof screen. If that's what people are looking for, it's not there.

MS. MACPHERSON: When you say judgment, do you mean something subjective? Do you mean a lot of factors?

MR. HERLING: As Kevin said, you run some basic analysis and you look at the results and you can do a certain amount of analysis pretty quickly and determine, yes or no, there's a problem, there's not a problem. But there's just no magic screen out there that says this generator will have no impact.

MS. MACPHERSON: Not one screen, not looking at one factor but, you know, we're interested in understanding what you do to figure out quickly which projects aren't going to be a problem?

MR. HERLING: Well again, it's somewhat case dependent. If you're locating in the middle of a city, short circuit may be the biggest issue. If you're located out on a distribution facility, you may have to look at some thermal issues.

MS. MACPHERSON: So there's a combination of location and other factors.

MR. HERLING: And the particulars of the project, yes.

MR. OLIVIER: We agree with everything that's been said before. We don't think there's a bright line threshold megawatt level that can give you the answer in all cases. If there were a fuzzy threshold, it would be more in the order of 10,000 -- I'm sorry, ten megawatts, not 20 megawatts -- but even then it happens to be in a very poorly chosen location even ten megawatts could be a problem.

For us, what we're looking at when we talk about streamlined studies, we're assessing whether or not we think there might be any stability issues. And smaller generators tend to have fewer stability issues. And when we can abbreviate a study, when we're comfortable with it, we will.

MR. PETTINGILL: I guess I would go back to my earlier comment and that is that what we're trying to focus on is the technical impact to the system, and so size almost becomes irrelevant. And Mark, I wanted to walk through a little bit in terms of the queue is a process in terms of saying you're next up for the study.

To the extent it's a smaller project, and we do the initial system impact study, as the other panelists have said, and it's not having any impact, then now in essence the project is now able to move along in terms of its construction phases because we've identified there's very little impact.

It may or may not require a facility study to identify the necessary facilities but certainly it's able to jump ahead, have the facilities study done, and actually go towards construction. And to the extent the facilities are minor, then it's certainly possible that that project could be on line before most of the other projects that are left in the queue.

Even projects ahead of it that had had a system impact study but had, you know, significant impacts and then would require a fairly detailed facilities study. It's certainly possible that if you look at some of the detailed data we've provided in the queue here, there are projected operation dates that are as old as 2001 or 2002, and those projects are on line but they're further down in the queue because they had less impact.

So just because we're talking about studies and where they pop up in the queue doesn't mean that the project still can't get on line or be operational before projects ahead of it, or even behind it because of that construction phase.

I think this is an appropriate place to talk briefly about the Rule 21 screens that I touched on earlier, and help folks understand. The biggest issue I think that we're struggling with on transmission studies is the fact that in most cases the transmission system is a network, and so taking a single point source and connecting it to that network has ramifications across the board. It's a little bit easier to provide for technical screens like what happens in Rule 21 because in most instances it's a radial system.

And so we're saying we're going to put a generator out on a radial line, and you can then assume very easily what's the power flow going to do. So with that, it was fairly easy for them to come up with these technical screens, identify screens that are appropriate for a radial connection.

But I don't want to leave you with the thought that all projects proceed with just going through those technical screens. There is the technical screen up front. There's eight of those screens that identify very clearly what are the technical impacts of a particular project. But if the project fails one of those screens, it still moves to a supplemental review, and in many cases that supplemental review is used to outline the study criteria that would be used for a system impact study because it's now clear it's failing the basic assumptions we had with the eight screens; now we're going to have to do a more detailed study to see what it's doing to the distribution network and conceivably what impacts it has on the transmission.

MR. REW: Our small generator threshold is 20 megawatts and I disagree with what's already been said. There really isn't a black-and-white rules that you can write out. You know you have to look at each case individually to determine whether or not it's going to be unique or whether there'll be other impacts.

MR. HEGERLE: You even have "if then" statements. Is there any way of doing that? I understand it can't be 20 megawatts or ten or five and every five-watt megawatt projects on, but is there certain things that can be written out that if you have this, then you might be able to move faster, or if you have that?

MR. REW: Well maybe defining if it has no stability impacts, no voltage impacts, no thermal impacts, without that exception, you know, it's just going to have to be looked at.

MR. ROONEY: We've about run out of time here but David, I think you wanted to make one statement and then we'll close down after you.

MR. CORY: Thank you. I just wanted to reiterate what Phil said is PacifiCorp's case, first come, first serve. What that means is that you're first in the queue for that point of interconnection and that we'll proceed with you as first in the queue. But if someone coming later in the queue, if they proceed in a quicker manner, they can precede you as far as the study and the process goes.

The other thing if it's a small, small generator, he can easily go through the process very quick.

MR. ROONEY: All right. Thank you very much. I appreciate you all being here today. Why don't we come back at, say 11:50. Thank you.

MR. ROONEY: If we could take our seats so we can get Panel Number 2 started please. Thank you.

(Pause.)

Just to let everybody know, the Chairman will be down here in a few moments. When he does come down, we'll just take a couple of moments to let him make some remarks, and then we'll go ahead and proceed. But for right now, Jim?

MR. CALDWELL: My name is Jim Caldwell and I'm the Policy Director for the American Wind Energy Association. And I have two generic themes before I get into my presentation. The first is, is that we are one of those customers who have perceived the seams and a gap, if you will, between the interconnection NOPRs and the SMD NOPR and really appreciate the willingness of the Commission to look at these issues in this forum and really think that this is an important piece of the record that needs to be completed before any of those NOPRs are released in a final rule.

The second generic theme I'll say is, is that our experience with queue management is very spotty around the country and that it's really a function of attitude rather than -- it tends to be more important than the process. And I think what that says is, it says that there is a need for more standardization in this area if it's that dependent upon the attitude. But secondly, what it also says is there's a limit to standardization in that it will always be the attitude that in the end prevails, and that anything that we can do to make this a more cooperative and interactive process, the better off we're going to be.

When we look at interconnection problems, we see that there are three significant sets of issues. The first and our Issue Number One is, is that it tends to be an untimely opaque process where we say the queue links of 18 to 24-months are common and also that the project engineering, the engineering for the project, must essentially be complete before the study begins. You have to define what it is that you're going to interconnect before you can begin the interconnection study process.

For us, that just doesn't work. In many cases, our project engineering is really a result of the interconnection study, not an input to the interconnection study. There are at least three different types of wind turbines that have different electrical characteristics for stability studies. There are several technical options for issues like reactive compensation that can be put in either at the turbine between the turbine and the point of common interconnection, or in many cases, out on the grid. And these have different engineering consequences, different cost consequences. And most of these, as I say, are the result of the interconnection study, not an input to the study.

Our solution for this is, is that we believe that there ought to be a generator self-study option for the energy-only or the beginning portion of the interconnection. If we can study it ourselves -- and that means (a) we have access to the right models, the data and all of that, that it is a transparent process, and we help that opaqueness. And secondly, then we can tailor when it is that we get serious about the interconnection, when it is that we enter the queue, much more in a timely way if that first step, the energy only, or in many cases, the interconnection study itself, can be done by the generators themselves, as is done in New York today.

The second issue that we have is, is that the sequential study process is inefficient and yields expensive results for both the generator and the grid. We end up with sub-optimum grid enhancements. I was listening to a story in the fall up in Carmel, Indiana where the SPP folks were talking about a time where the interconnection was made, and three weeks after the interconnection was actually energized, they found out that, gee, if I'd have looked at the next line in the queue instead of reconductoring that particular line one way, I would have done it two sizes larger and saved a lot of money and time for everyone.

We have the zombie project problem that we've all talked about. And then there's constant do-overs as all these projects evolve and as all the queue changes. In the out-of-queue order studies that New England ISO and MISO talked about, they are required by common sense, but they really don't solve the problem. Because what they end up doing is, is they say, okay, you can interconnect, but your interconnection will be contingent upon these events that may occur five years after you are actually on line, and you may be liable for significant interconnection kinds of monies five, six years down the road, and they're not able to bound what that liability is. And therefore, your project ends up not being financable.

The third generic issue that we say is that in many cases that the worst case peak day analysis is used unappropriately. And by that I mean that many of the interconnection issues or many of the congestion issues that take place tend to occur rarely or they tend to concur on contingencies.

And so what you end up doing is, is you are asked through the interconnection process to effectively cure congestion to the level of one day in ten years. And at that level, most of the congestion that you're asked to cure is almost by definition uneconomical to get at.

And so at that phase of the study, we believe that there needs to be the chronological dispatch models consistent with the SMD pro forma tariff for generator redispatch so that we can look at congestion duration analysis and remedial action schemes as opposed to just saying that there is no interconnection available.

Thank you.

MR. JIMISON: My name is John Jimison. I am the Executive Director and General Counsel at the U.S. Combined Heat and Power Association. We were very active in the ANOPR consensus seeking process on small gen interconnection as part of the small gen coalition. So to a certain extent, I'm trying to speak for that broader coalition.

I just want to make a few points to supplement or to reflect what's in the slides that I handed out. We were asked to come up with war stories about small gens who had a problem because of queuing policy. And so we surveyed the whole group. And basically what we learned was that the problems of queuing policy are really not distinguishable from the other problems of interconnection policy; that if your project is held up because a study is taking six months, it doesn't really matter and you don't really know whether that's because you're behind somebody else in the queue for that study or because the study itself is taking six months for lack of resources allocated to it or whatever.

And what that leads to is our conclusion that you really cannot have an expedited interconnection process for small generators unless they are in a separate queue for small generators, that the queue equals the interconnection process in a certain sense.

So in thinking about how to deal with this, we believe that there should be separate queues at the application stage for small generators and that the entry of small generators into those queues should replicate the distinctions within small generators that came out of the consensus process for interconnection. That is, the super-expedited 2 megawatts and less small generators, which by definition have no system impacts, can, as some of the companies earlier suggested they did, avoid a queue entirely.

Those small generators from 2 megawatts to 20 megawatts, which are in the Attachment B part of the consensus document, yes, they can have system impacts. They do need studies. They should be queued for the conduct of those studies among themselves.

However, when it goes to the point of assessing the addition of new facilities to the grid, obviously that has to be done for small as well as large generators. And so our suggestion is that you create what I've called in here a system facilities queue, where all those projects, small and large, whose impact studies have been completed within a three-month window, would be clustered for the purpose of assessing system upgrade requirements, and those requirements would be studied, the costs of the system upgrades would be allocated proportionate to capacity to those projects, small and large, in that group.

Those projects would then have to post a bond to pay those costs upon completion of that study or within a reasonable time afterwards. And upon payment of that bond or posting of that bond, those projects would then have prepaid their interconnection or their system upgrade costs and would have the certainty that is so critical for small generators of what those costs would be and not have the uncertainty that is currently there about your costs being entirely dependent on whether someone ahead of you in the queue does or does not eventually interconnect.

We also believe that would reduce the needs for restudies.

Once people had their facilities needs identified or their share of the facilities needs identified and had posted their bonds, they would be free to go ahead and interconnect at the rate in which they were able to do that. And by doing this, small generators could benefit from one of their inherent advantages, which is short lead times, off-the-shelf equipment, easily understandable technology, very limited if any impacts on the grids, and the ability to get interconnected quickly.

So in summary, we think queuing policy needs to reflect interconnection policy in general, and that in order to allow small generators to respond to their advantages and deal with their disadvantages, it needs to be done separately.

Thank you.

MR. ROONEY: Donald?

MR. JONES: Thank you. My name is Don Jones. I'm the Director of Transmission Asset Management with Xcel Energy Services. Xcel is one of the entities that is working with a number of other transmission providers in the establishment of the Translink Independent Transmission Company.

I would like to thank the Commission and the Commission Staff today for this opportunity to visit with you all. I also would like to thank Norma for switching my name placard from Sam to Donald, although that might have given me some opportunity to speak more freely.

(Laughter.)

MR. JONES: And I'd also like to preface my comments that I wake up every day seeing an ocean of opportunity for improvement, but it does not preclude me from recognizing the progress of the Hawaiian islands.

Now if I could direct you to my slides. What I would like to share with everybody here today is just some practical experiences as a transmission provider.

We have gone from a paradigm from where we were first managing our own queue, and then we transitioned to the MISO and SPP queue. And so we have some perspectives of having dealt in both those worlds of operating our own queue and then under the Independent System Operator.

In those regions, on my second slide, is the MISO queue impacts as we know them today that involve our transmission system.

We've got 33 active interconnection requests. What's interesting is that it totals 8,155 total megawatts. Of that total, over 1,000 megawatts of it is wind generation, and I can tell from the composite of the panel here there's much interest in that.

What I find interesting also is that nearly all that wind is in the same general geographic area of the transmission system. And this is, you know, from a transmission perspective, our guess is that most are buying for a selection in a well known RFP that has been issued by NSP in Minnesota. So that is the market that we anticipate that they're actually buying for.

What that somewhat suggests is that the queue and its totality may not have any relationship to what actually eventually gets built.

In the SPP area, we've got 15 interconnection requests. They total 5,760 total megawatts. Very interesting, over 5,000 of that is wind generation.

What I also find somewhat of a remarkable statistic is that the peak load of the control area there is just a bit over 4,000 megawatts.

The wind requests not only exceed the peak load but, as recently as I have checked, the estimate export capability of the transmission system is somewhat about 600 megawatts. So again, I'd also point out that 92 percent of these wind requests tend to be in the same geographical area and that I'm doubtful that the queue actually represents ultimately what may be built.

One of the observations that I was looking forward to perhaps participating in the discussion today is with those types of facts, whether or not we might handle certain elements of the queue implication such as transmission rights, cost allocation and system analysis on a separate basis.

For example, in experiences that I've had dealing with a wind development, I'll use one example in Southwest Minnesota. When we were running a sequential queue at the time, the studies were progressing very slow and very laborious. After some review, we worked with the various developers at the time and combined many of the interests, since it was in the same geographical area, and did a tiered approach in evaluating the transmission requirements to accommodate various levels of wind development even though the interconnections themselves didn't necessarily at the time warrant the various levels that we were going to.

In the end, I believe that the aggregation approach that we used seemed to satisfy the need of the developers at the time for the information that they needed, and also that the state of Minnesota, who is interested in seeing this development occur, has the information before them in the context of a certificate of need to build the necessary transmission to accommodate this wind generation.

And I see that my time is up. Thank you.

MR. WILLIAMS: Yes. I'm Wes Williams with Southern California Edison Company. I'm currently manager of ISO FERC regulation, although up until October of last year, I was manager of Grid Interconnection and Contract Development.

Southern California Edison has had a considerable amount of experience with generators trying to interconnect to the system, and we welcome the opportunity to come share some of those experiences today to hopefully arrive at a process that is workable for all.

If you look back about a year-and-a-half ago to

June of 2001, we were processing requests for interconnection to our system that were on the order of 21,000 megawatts. This was a period, as you'll recall, that California was facing supply shortages. Prices were very high.

One year after that in June of 2002, that 21,000 megawatts had been reduced to 9,000 megawatts of applications that we were looking at, a significant difference. And I've listed some of the statistics in the slides if you want to look at those later. I won't get into a lot of detail on that.

But you can note in there that we were in essence receiving withdrawal of application on the order of about one per week. It was coming in very rapidly. Things were changing very rapidly.

We learned several things out of that. I think one of the main things that we learned that was because of the cumulative impact of the generation, that the restudies that are required can be very time consuming, and they can be very costly to a generator who has to pay for the original study, the restudy and the one after that, particularly when you can't even get the study done before things have changed and you're looking at a restudy again.

Another lesson that I think we took from that was that the allocation of costs of interconnection is very difficult when you try to do that through this study process. If you instead go to the process that the Commission is now looking at where costs are paid up front by a generator and then credited back, the cost allocation doesn't become quite as important. So I think there's some merit in going to that type of a system.

It does necessitate, though, that you do have costs paid up front so that you can mitigate project development risks. And I'll go through an example a little bit later of some of these that we saw in real life.

A few other lessons that we took away and recommendations that we would have as we look at this. First of all, projects should be queued after the receipt of a completed application and complete project definition. Without that, we find that we are holding up later queued projects trying to get information on the earlier queued projects.

Cost of network upgrades, as I indicated before, we think should be rolled in with generator up-front funding and credits. We think this needs to be part of the overall regional transmission planning process. And I won't get into the details of that, but I did provide in here a reference to our SMD comments where we had gotten into that in a little more detail.

Queue milestones are needed. We did not have sufficient milestones in the past. We think milestones are very important. We also think that a single regional or wide geographical queue is required. And along with that, we think reciprocity provisions are needed to bring in some of the nonjurisdictional entities that are out there, and particularly in the West where we have a number of nonjurisdictional entities.

A couple of specifics in terms of experiences that we've had. We had one applicant, 1,000 megawatt project, and was adding to an existing project. We went through the study process. We signed an interconnection agreement. We began construction.

After we had done all that, we had a whole series of things happen. They requested a modification to leave the existing portion of the plant connected at the transmission voltage that it was originally connected at.

They asked for a 90 to 120-day delay. They then failed to make a periodic payment for the construction of the work. They then asked for an indefinite delay.

And this scenario went on and on and on for a considerable period of time. And what we found was that we could not really go through looking at the subsequently queue generation because of all the changes that were going on with this.

So I think that drove home the point to us that we need specific milestones to keep these projects in the queue, and that we need sufficient advance funding to mitigate the project development risk.

I have a couple of other examples that I've listed in the slides and the handouts there. I think in the interest of time, I see I'm running out of time, I will not go through those.

I think, though, that I would say just in summarizing those couple of slides, that we do think that reciprocity provisions are needed in the Commission's orders that come out so that we can bring in nonjurisdictional entities to be consistent in the way we handle all of these.

And we also need to have full information up front in our queue so that we're not holding up later queued projects waiting for information as we go through the process.

Thank you.

MR. THOMPSON: I'm Justin Thompson. I'm the Transmission Strategies Manager for Pinnacle West Energy.

Pinnacle West Energy is a subsidiary or an affiliate of Arizona Public Service Company. We are the competitive generation arm for Arizona Public Service.

One of the goals I'd like to see out of these proceedings today and all this work that's gone on to date, is that a clear set of rules are established so that all of the parties understand what they can and can't do, and we avoid a lot of the disputes that we've had to go into and had to come to FERC to resolve. I think that's a good goal for this process.

One of the things I want to talk about today is clustered queue, regional queuing, milestone importance, and the impact of non-jurisdictional entities.

I have some good examples of some things that worked very well and some things that FERC needs to establish rules to avoid. I want to talk about the Palo Verde Hub example.

In 1999, we had 11 interconnection requests. Four of them were for transmission lines, and seven were for generation projects, totaling about 8600 megawatts. The problem, from the transmission owners' perspective, was how do you queue these sequentially? How do you deal with a party that drops out?

What if one of the transmission lines projects drops out? What if it goes forward? What if Project No. 3 in the queue drops out?

So what the transmission owners did -- and they did a really nice job -- was, they performed a cluster study. They did the studies based on all of the projects being completed, and then took out a project, one at a time, to see what the impacts were.

Once these transmission studies were done, they estimated the cost to interconnect. All of the parties were given the opportunity to proceed.

The ones that committed funds and signed an interconnection agreement went forward, and one of the important parts of this whole thing, one of the lessons we learned was that the money had to be posted up front through security.

By posting that, the parties that weren't serious got out, and the other parties went forward. Some of the results of that were that all of the parties that wanted to connect were accommodated. We got rid of the projects that weren't serious and we moved on.

Now, one of the things that happened throughout this process was, there was a party that came in two years down the road, after a lot of the projects were already completed or were near completion. And they wanted to connect to an adjacent system.

Well, this party was the first in the queue in the adjacent system, so when the studies were started, when they started the studies, they ignored the fact that there were any of these other projects already underway.

That started creating some problems, so we worked that out by talking to the transmission owner to make sure that all of the projects were taken into account, and that it was a regional type queue.

But there is that opportunity for gaming out there, and I just want FERC to recognize that that could be a problem, and that they need to pay attention to that and establish rules to avoid that.

I want to also talk about a project we're doing in Las Vegas. We had a similar situation -- multiple generation projects connecting to a common area at about the same time.

And the way to work out the queuing, we did a clustered queue, studied the impacts of all of the projects together. The projects that wanted to go forward had to make financial commitments.

Once the number of projects that were going forward was established, then the project was re-scoped and the costs were reallocated.

Now, that seemed to work out pretty good, and all of the projects, again, that were serious were accommodated, and we moved forward.

Now, some of the problems that we're experiencing through this process is dealing with the non-jurisdictional entities. They don't follow the same rules. They establish their own rules; they don't have milestones; they don't have clear procedures on how to proceed.

And so it creates, in a way, anarchy out there, because they establish their own rules. And we want to move forward; we want to do the right thing. We're willing to contribute to upgrades when they are appropriate.

FERC has said that transmission credits are due when the generators pay for upgrades. The nonjurisdictional entities say that, well, we don't have to pay for upgrades or we don't have to issue you transmission credits.

And so that puts a burden on the generator, and it disrupts the whole process, because there are two sets of rules out there.

I just want to point those things out, and I see I'm running out of time here.

Some of the major concerns that we have, again: Nonjurisdictional entities, the process; the somewhat slow implementation, and no milestones to eliminate projects that aren't serious. Thank you.

MR. SIMPSON: I'm John Simpson, Director of

Transmission Analysis for Reliant Energy. Reliant currently has approximately 21,000 megawatts of generation in the U.S., and over 6,000 megawatts of this generation is new generation that we have developed and placed in service in the last four years or so, or that we currently have under construction.

We've also done a lot of development work that we started, proceeded through interconnection requests, and then later either withdrew or sold to other IPPs or developers, so we have a broad background to share our experience. I appreciate the opportunity to do that today.

First, I'd like to share some good experiences with the queue process. In my opinion, PJM is a pretty good example of a good queue process.

It retains the principle that first requests in have first rights at the existing capacity in the grid. Then as upgrades or enhancements to the grid are required, those generators that contribute to the need for the enhancement share in the costs, based on their proportionate impact on the need for the upgrade.

PJM also has some flexibility built into the process that allows generators to make adjustments to the projects as they proceed. The flexibility was better in the A-Queue, the first queue that they did for new interconnections, in that they allowed a project to change its size by a range of plus-ten percent to minus-50 percent.

This actually benefitted one of our projects, our Hunterstown Project. It was initially proposed as a two, two-on-one combined cycle project. As we started development work and did some engineering analysis, we found it was much better for us to change that project to a single three-on-one combined cycle.

The two two-on-one's had a capacity of about 1200 megawatts, the one, three-on-one was about 800 megawatts. Due to the flexibility on PJM's process, we were able to accommodate that change, make that change.

Unfortunately, PJM has reduced that flexibility in future queues, so that a developer can only change by a plus or minus ten percent.

Next I'd like to discuss some bad experiences with the queue process: In PJM, our bad experiences are primarily just getting studies done, getting them out in a timely manner.

PJM has gone through great growing pains with all of the requests that they had. Their cycle has been extended, first from three months to a four-month and now to a six-month cycle.

These are long periods of time from the initial request to the first study results. In Florida, we had an experience where a generation interconnection request and several transmission service requests were made to a transmission provider.

The provider completed the initial study and determined that impacts would occur on neighboring systems. Actually, I believe the transmission provider knew this beforehand and went through his study process just as a simple matter of this is what I do under the OATT and I have to go through this process.

After the initial study was completed, another long delay ensued while all of the other impacted systems got together to run a composite study. This was compounded by the fact that there were other generation requests and other transmission service requests in the queue that were on these other systems.

To make a long story short, it took a long time to get the studies done to get all of the impacts analyzed, and, in fact, by the time we were down the road then of getting the upgrades built, it was too late to provide some of the service that had been requested by the generators.

In Nevada, we had a similar experience, but those problems were even greater. This is another case that was multiple generators requesting interconnection service and transmission service onto multiple transmission owners.

The TOs -- some of those TOs are FERC jurisdictional; some are not. The transmission provider conducted the initial study for the projects, connecting to his transmission system, however, when impacts to third-party systems were identified, a new joint study had to be completed with all generators requesting interconnection in the region.

Due to the different positions held in the interconnection request queue and the separate transmission service request queue, there had to be an understanding and agreement reached among the generators to just share in the cost of upgrades or else we would have had a long battle over who is first and who is second and who is going to pay for what.

It was only on the part of the generators agreeing not to fight that battle, that we were able to go forward.

Additional difficulties were encountered with having the provider negotiate or coordinate with third-party systems on impacts due to the interconnection requests. These reasonable efforts, which are required in the tariff by the transmission provider, are not adequate to protect the interests of a generator who is exposed to network upgrade costs.

The generator and the third-party system need to be forced to interact directly on all network upgrades required by the generator's interconnection request.

This brings me to recommended solutions: Reliant strongly believes there should be one queue for all interconnection requests within a geographic region. That queue should include all generation interconnection requests, large and small, and it should encompass all transmission owners in the region, whether they are FERC jurisdictional or not.

When interconnection studies are done, all transmission owners should be required to participate in the study, whether they are under FERC's jurisdiction or not. Transmission providers, if they don't, our experience shows that re-study is required.

FERC can use its reciprocity provisions to try to draw in those nonjurisdictional entities. Thanks.

MR. ROONEY: Thank you, John. We're going to take a couple of minutes here. I believe the Chairman might want to make some introductory statements.

CHAIRMAN WOOD: Sorry to be so late. I was giving a speech on distributive generation, so if you don't solve all these issues for big generation, then we'll solve them for little generation and they'll be a country full of little generators, and all the big ones won't be there.

We've got to solve it for everybody, and I appreciate the participation of you guys on this panel, the first panel, which I caught a little bit of on TV.

I just wanted to say that I appreciate the efforts that y'all are doing to nail down this important and critical piece that we keep showing up every single docket, just about, dealing with interconnection, has some tendrils in the issues y'all are discussing today, so thank you.

I wanted to also use this opportunity, publicly, to thank an individual who has been with us for the past three months as a technology fellow, our first ever technology fellow, Mr. Eric Wong. Come on up here, Eric.

(Applause.)

CHAIRMAN WOOD: Eric came to us from Cummings, and we appreciate them loaning you to us, and Eric's contribution to us has been not only what we're doing here today, but on a number of issues related to the -- I guess I want to call them the nontraditional aspects of the electric power grid that are becoming more and more a central part of what we're doing.

So I want to read y'all -- while a lot of y'all he's worked with are here in the room, I wanted to just piggyback the opportunity to thank Eric. This is presented to Eric R. Wong, as FERC Technology Fellow. I should add that he's our first, and due to the great experience, not our last.

"For aiding FERC and the nation by sharing his insight and expertise on distributed generation, interconnection, and demand response, to improve the effectiveness of the electricity competition and national energy security; given with much appreciation and best wishes on the occasion of your departure from FERC today."

(Applause.)

CHAIRMAN WOOD: Thank you all. I'll keep listening in here over here on the side bench.

MR. ROONEY: Thank you, sir. Donna?

MS. REED: My name is Donna Reed. I'm a senior buyer of global energy sourcing, International Paper, and I'm here on behalf of the American Forest and Paper Association.

First, I would like to thank you for the opportunity to participate on this panel today. Many AF&PA member have attempted to gain access to the grid in order to sell excess power. Negotiations with utilities were lengthy and sometimes exceeded 18 months, with many barriers such as unjustified interconnection application fees of $10,000 or more, extensive paperwork for system impact study requests, expensive up-front costs, unnecessary metering upgrades, compulsory imbalance requirements with steep penalties for any power export deficiencies, mandatory administrative charges, required even when no power was even exported to the grid; burdensome metering and reporting requirements, and costly system upgrades.

In most cases, the economic window of opportunity to take advantage of power sales to the grid were gone, due to overextended negotiations. AF&PA supports the Commission's efforts to standardize interconnection procedures and agreements.

Simple and uniform procedures and agreements should be created for small generators. Imposing interconnection processes designed for merchant plants or small generators will be expensive and burdensome.

Even though the Commission has stated that rules concerning small generators would include those with capacity up to 20 megawatts, AF&PA proposes that generators up to and including 50 megawatts be eligible for small generator interconnection agreements and procedures.

Generators of this size will have little to no impact on the reliability and operation of the grid. No interconnection agreement should be required for existing, new, or expanded QFs that are 50 megawatts or less.

Small generators should not be treated as network resources. Small cogenerators that are an integral part of the manufacturing process cannot respond to automatic dispatches by an ITP to meet emergency or system supply requirements. Such actions could severely disrupt manufacturing operations, affect environmental compliance, and threaten worker safety.

Cogenerators need to coordinate with the transmission provider to determine the economic and operational feasibility of any dispatches to the grid.

To summarize, system impacts should be based on net capacity impacts to the grid, not gross capacity. Complex interconnection requirements impose burdens on small generators.

No interconnection agreement should be required for a QF if power is not physically delivered to the transmission grid. For existing QFs, once connected, always connected.

The interconnection process should be quick and simple. Interconnection procedures and agreements should take into account, requirements of the host plant and not hinder retail electric service to the host plant.

An industrial with onsite generation cannot agree to an interconnection agreement or market rules that allow the transmission provider, dispatch rights over the industrial's generation assets. The Commission should recognize that any rules should take into account, the unique status of onsite generators, particularly QFs.

QFs must not be subject to the same operational requirements as merchant power plants, due to their integration with the manufacturing process.

MR. ROONEY: Thank you, Donna. Jolly?

MR. HAYDEN: My name is Jolly Hayden. I'm the Vice President of Transmission Operations with Calpine. First off, I want to thank the panel and the Commission Staff for allowing me to be here on behalf of Calpine, as well as accommodating my scheduling requirements. Just, FYI, if my wife does go into labor, it's been an honor to be able to work with each of and every one of you, because my life is over as I know it.

(Laughter.)

MR. HAYDEN: I pray to god that the snow does not cause a problem this afternoon.

While Calpine appreciates the opportunity to be here before FERC about our problems that we have encountered with the interconnection queuing process, we would urge FERC to issue a final rule as soon as possible.

To paraphrase a comment that Chairman Wood made about a year ago, related to this transition process, this transition process is costing the energy industry a lot of money.

With respect to the queuing problems, we think a lot of issues would fall by the wayside if FERC would make a decision on cost allocation. So Calpine is very supportive of the FERC coming up with a decision on this cost allocation process.

And a case in point is, you know, go to the one extreme of ERCOT. The queuing process is not a big difficulty in FERC, just because of the way the costs are allocated. That's a case in point.

What I would like to focus on, while many of my colleagues here across the table already addressed some concerns of Calpine, such as some concepts of regional queuing, cluster queuing, the significance of establishing milestones, the reciprocity -- don't get me started on reciprocity and the nonjurisdictional issues, because I will be here for two weeks.

I would like to focus on the participant funding itself, and state that Calpine, in general, does not have a problem. We support participant funding.

The key issue is what does that mean? Number one, the referee needs to be an independent entity who makes the decision on cost allocation and benefits.

Participant funding liability is assessed on studies performed by an independent party, and takes into consideration, system constraints based on economic dispatch, so not the way we've been dispatching over the last 50 years, but how, if we had an efficient market, how would a market-based dispatch be? What impact would that have on my facilities or proposed facilities?

It fully recognizes -- independent entity fully recognizes all system beneficiaries of upgrades and allocates those costs accordingly. It ensures that the entity allocated upgrade costs, receives the benefits of the upgrades that they've funded.

And we would argue that until such a system is in place, that the current policy stay in place.

With that said, I'd like to focus on a couple of examples of some of the problems that we've been having throughout the country. Number one, lack of responsiveness has been touched on a little bit across the table. I can point to an example where it took us 16 months to complete a generator interconnection study, and an additional 11 months to wait to get an interconnection agreement, a draft of an interconnection agreement.

And, by the way, we're still waiting to get all these issues resolved, so it's three years for some of this process to put a plant in that we can engineer and construct in about 18 months.

When a company drops out of a queue, was touched on earlier as well. The TO, you know, needs to do a re-study or is compelled to do a re-study. There is obviously a couple of different methods that this is accomplished across the country.

I can point to an example out West with our Las Esteros Project, where this has happened four times, and each time we have incurred incremental additional study costs of $20,000 a study.

Asymmetrical bargaining power: This is another area that is touched on recently, particularly as it pertained to the nonjurisdictionals, but the bottom line is that the transmission owner, in the cases where the vertically integrated utility that controls the wires, most of the load, and most of the generation in the neighborhood, controls -- have all the power.

They say you do not sign this agreement, we do not lay one brick; we do not start one once of construction, even though, you know, we're willing to immediately lay out an LC to fund the construction to eliminate their risk. Obviously, that forces us to accept conditions that we find less than favorable.

The last comment I will make is about excessive credit requirements. Calpine has over $200 million outstanding to support gas transportation, interconnection, and transmission service agreements.

Of that $200 million, in excess of $20 million is for collateralization of tax indemnification obligations. Obviously, the issue of credit is very important, and the LC requirement is a major burden that is put upon the generators. This needs to be resolved.

We believe FERC's issuance of a final rule will help this problem. I look forward to the Q&A. Thank you.

MR. ROONEY: Thank you.

MR. HENRY: We have heard repeatedly in the first session and this session, too, that it seems that a major villain in the interconnection process is the sequential study. And repeatedly we've heard people speaking in favor of the clustered study.

Is there anyone who has any strong opinions in favor of a sequential study process?

MR. WILLIAMS: I guess maybe I would put that back a little bit on the definition of a sequential study process versus a cluster study process. In my mind, when you say "sequential," it does not necessarily mean that one study is done and when that is complete you do the next study and then do the next study.

But the generators, the individual generators are individually queued, and we're looking at the individual impacts, sequentially, of those generators coming online.

That's primarily the way we've done it in Southern California Edison. The problem we thought we would run into with the clustered version was that when you do cluster them and you do have a fluid situation where generators are dropping out of the queue regularly, by the time you get done with that study on the cluster, you still have a study that is not up to date, so I don't think that it necessarily solves the problem.

MR. CALDWELL: I don't see how we're ever going to get there without a cluster study, at least in some part in the process. I think in order to make the cluster studies work, first thing is that you have to sort of vet the things that get into the cluster, and so there has to be something ahead of the cluster. If all you had to do to get involved in these cluster studies was fill out a one-page application, then I don't think it would work either. People would use it too much at the front end.

But with the significant front end which we believe needs to be sort of a generator self-study piece of the equation where we get a chance to have access on an equal basis to the load flow data to the stability date to the models, and we have the opportunity to do it ourselves, and to see the consequences of that and to recommend changes or to design changes to our interconnection in order to make sure that we get some of that stuff done, then I think the cluster study becomes really important.

I'm really intrigued by the experience in New York which I think is a more highly evolved and a little bit more detailed set of protocols that looks a lot like PJM in concept but I think has been taken to the next level, and I really recommend that this Commission look at the New York study process as a good model here.

MR. HAYDEN: Let me touch base on what Mr. Caldwell mentioned about the clusters and related the study information. He's a hundred percent correct. One of the problems that we have had over the years -- it's gotten better in some regions than others -- is the base case information. It is considered by some entities as confidential information, we will not give it to you, you can't have it, and the likes. And I would argue that as a result, the merchants are operating in the blind, and we've had probably more projects proposed to the transmission companies that really are in a bad location and if the generators had better access, they wouldn't propose that.

And to the clustering effect, I mean as we look at Calpine's participation totally it's related but it's the TSR, the transmission service request, working with MISO on how to clean up their queue process related to TSRs. And it's a similar process. I mean there are some key elements out there that whether it be your project or my project or her project, we're all going to impact and there is a way to sit there and group these, and again using set milestones we'll find out who's real, who's serious, and who's not.

But it all starts with the base case. Let's make that transparent. Thank you.

MR. HEGERLE: For the transmission providers here is there transparency, do you offer transparency in the base case here?

MR. WILLIAMS: I think as Phil Pettingill of the California ISO had spoke on the last panel, there is transparency in terms of the base case which uses the ISO or WECC base case. The problem I think comes into the area of the generators that are in our queue that have applied for interconnection. The details of those generators are not necessarily in the base case, not necessarily known to others, and we've been asked to keep them confidential so we're pretty much stuck between two difficult choices, the generator asking us not to divulge a tariff that also provides for some confidentiality, and on the other hand others asking for that information.

MR. HEGERLE: Can it be offered in some form of a range of expected results or anything. Is there any way of offering more information than you do now without giving away specific details of the plan generator?

MR. WILLIAMS: I think part of the problem is to actually do the modeling to run the studies, you need the information.

MR. JONES: I'd like to go back to the previous question and also talk about the transparency. I want to make sure that I understand and we understand that we're not going to exchange one silver bullet for another silver bullet. The characterization that the sequential process is either all good or all bad is not correct. The characterization of an aggregation process is all good or all bad is not correct.

Which fundamentally in my mind is that the transmission side of the business has to have some sort of flexibility, and also accountability, and providing the necessary information that the developers or the market need. It is within the ability of the transmission side of the business to look at the request, look at the market interest and construct study efforts that more efficiently get to the information that the market wants.

Sometimes it'll have elements of sequence; sometimes it'll have elements of aggregation; sometimes it'll be based on geography; sometimes on timing, and a combination of all of the above. But as a transmission provider, I am receptive to having that responsibility and having milestones to provide that information in a timely manner. But I need the flexibility to be able to structure the study efforts in such a way that I can do it efficiently.

Some of the hindrances to structuring the studies in an efficient manner have been touched upon. It's the implication of the cost allocation. There has to be some sort of resolution, I agree with some of the comments earlier, that the issue of cost allocation has to be resolved.

If the results of the study are going to determine who has to front the capital investment for the transmission construction, then there's going to be significant continued interest on how the transmission side of the business is conducting that study, and it will be time consuming.

If you lessen the implication of the participants in the market having to front the transmission construction, then they will be more receptive to the efficient application of study efforts that the transmission provider might do.

That kind of leads me to that second question that came up, the transparency. Part of this, perhaps suspicion or mistrust about how the queues are being managed in my mind is driven by the lack of transparency. The transmission side of the business I think needs to be able to make it's planning processes a bit more open to the developers. I agree that the developers need to see and have access to more information so they can do a reasoned business analysis about how they're going to proceed.

But that also means that the transmission provider should be able to be a bit more proactive in providing information. I mean I've seen examples of insisted-upon instances in our own practice of providing transmission service, where a system-wide analysis by BUS identifying injection capability on a simple thermal basis is being provided to the marketplace.

We can make great improvements in terms of that transparency of the information so that we can have reasoned discussions about generator locations.

MR. ROONEY: Jim?

MR. CALDWELL: I was going to say I was glad to hear Southern California Edison say that they make available the base case. Then we can take off a couple of the things that are on the current FERC docket where our members have actually been denied the base case from Southern California Edison. I don't say that as a means to try to talk about attitude and I think there is a lot of movement towards more transparency but that this needs to be jump started, it needs to take place quicker, and one of the principal ways that's going to happen is is this independence idea to put the queue management, to put all these issues in terms of the ISO and the RTO instead of the individual utility involved will help a lot.

In the case of the Edison, we were able finally, after a while, to get the base case studies through the California ISO and we think they're the same ones that Southern California used; we're not sure, but that's got to change, and we're not talking necessarily about people's attitude. It starts with I think that making the queue management be at the independent level, the ITP level, the RTO, the ISO, and then all of those institutions as part of their normal daily thing have protocols for dealing with confidential information and how they get released and need-to-know and all that sort of stuff, and we can use those protocols. But as long as it is individual utility by utility, we're never going to make it.

MR. ROONEY: Thank you.l Jolly?

MR. HAYDEN: I'd like to address a little bit what Mr. Jones mentioned related to the liability, that briefly touched on my little five-minute discussion and as I refer to it, skin in the game. An example that I didn't share with you earlier is, and this happens with us everywhere, is you know, we are under a time crunch, particularly in this day and age when, you know, I'm not going to be building any merchant plants unless I have a contract to back it up, and that's fine. But I get a contract with a load serving entity amenable to municipal coop or the like and I have a deadline.

You know, I have damages that I am subject to if I don't meet my deadline. Well, I'm not getting the same kind of response out of the transmission provider. They no skin in the game, they have no liability, you know, if they fail to deliver the studies in a timely manner or fail to deliver the IAs I gave earlier. And that is a problem I have had for years and many times in front of this, you know, in this room, have mentioned that. That is an issue that we have to resolve, and it's a concern I have when we go to an RTO or that type environment because they are non-profit and the like. So that's something else I want you to consider.

Cost allocation. That is again we all touched on it but let me emphasize, as an example, going down the path I was describing, you did some of our internal studies based on the flawed base cases that we could get our hands on because it was less than fresh information, we came back and did an assessment of what we thought our risk was because we couldn't wait on the provider to give us that.

We then based our decision on do we go or no go on the project again because we had this timeline to solve some of our contracts. Well, lo and behold, when they finally came back, I mean we had a pretty wide bid-ask spread between what our view of the network upgrades were and what their's was. And the interesting thing about that is, as you looked at it, they were getting us to pay for some overloads that had existed for ten years. In the last two years alone, there were 266 TLRs, but they had chose to just live with that.

Now again, you have an independent entity who's sitting there, who's not a vertically integrated utility, you establish the correct rules. You know, I would have an allocation of that but so would they. That's just a good example I wanted to share with you. Thank you.

MR. ROONEY: Wes, did you want to respond?

MR. WILLIAMS: No.

MR. ROONEY: This question by the way will be both I think Donald and Wes. Do you all plan on an integrated basis factoring in plant transmission expansions when you for your generator interconnection studies? Or are they viewed separately? Wes?

MR. WILLIAMS: We look at transmission and generation when we do the studies. We think they all belong in one queue, that the entire system needs to be looked at.

MR. JONES: For the most part, they're combined in the study efforts as their allowable.

MR. HEGERLE: I think where the question's going, and maybe you've answered it but I'm not sure, is I know you have plans for transmission in and of itself. Do you factor in what you've already planned on a long-term basis for transmission into a generator interconnection request, and you know either accelerate the installation of some system expansion that you would plan to do say two years from now to meet this generator interconnection request? Or do you view them separately?

At PJM, if you ask for something that's in the plan, then you only pay the difference in timing, you don't pay for the whole thing.

MR. JONES: If I'm understanding the question, if the intentions already exist to construct a facility and a generator interconnection comes in after that intent has already been made, if there's some way to aid the development of the project by advancing the addition of the transmission element, yes.

MR. WILLIAMS: I think we're similarly situated. To the extent that we have transmission or any system upgrades noted in our five-year plan, and to the extent that then can be utilized by a generator, we would try to move that up in time if that's possible. We also do not charge the generator for that. If it was already in our plan, we view that as something that we were planning to do and we would fund.

MR. HEGERLE: I guess looking at it from the other side as well, you know I know you mentioned a lot of wind coming in in one area. Do you look long-term and seek to modify your plant to respond to the market signals of generation appearing at various places, or not?

MR. JONES: Yes. I found that the experience instructive in southwest Minnesota where we had a bid under 300 megawatts of wind generation already in in existence. The available transmission above that was zero. There's significant market interest expressed by various wind developers. Also the State of Minnesota, in and of itself, is very proactive in trying to develop it. We know this.

And so as we were getting the requests in one at a time in a sequential basis, I'd mentioned earlier that we started to get bogged down in our evaluation process. And it's not an exaggeration when I say that if we would have ultimately come out with a build all plan to accommodate the request, there would have been a re-conductor here, a rebuild here, a re-conductor here, and so forth, on very low voltage transmission facilities.

I had asked that we reaggregate our thinking so to speak on evaluating and in fact over-shoot the known interconnection and transmission service requests that we had associated with the wind. If you will, an educated judgment about what the market potential for ultimate build out was out there.

As such, the transmission plant, to accommodate it is well-known, and I mentioned earlier is filed with the State of Minnesota for a certificate of need approval.

MR. WILLIAMS: I think when you bring the wind generators in, you bring in an interesting case. We are currently involved in a planning process with a number of the wind generators and it's being done in conjunction with the California Public Utilities Commission. We do have an area in California, in southern California, that is transmission-constrained, and it is an area that is conducive to wind development.

So we're in the process of doing studies and trying to look at that. I think you've got a little bit of a chicken-and-egg situation, though, when we talk about wind generation. Obviously a single wind generator cannot support a major transmission development to get the generation out of the area.

On the other hand, for the utility, without assurance of cost recovery, it's very difficult to put a transmission upgrade in without knowing that that generation will be there. So I think it starts to tie all your queue discussion and your wind discussion, all comes back to cost and to assurance of cost recovery when you do put in upgrades to accommodate them.

MR. JONES: If I may, let me chime in on that last remark with the example that we had in southwest Minnesota. What I have failed to mention is that the State of Minnesota also put in place a cost recovery mechanism for transmission that's built specifically for renewable resources. And so again, we will come back to the issue of the queue and that cost, getting the cost allocation issue is very important.

MR. POOLE: I had a general question similar in that when you're doing queuing and you're looking at a cluster, it would say to me that if a cluster is say a six-months cluster, in other words you study things that come in in a six-month period or say in a three-month period, depending upon what you have as your window for the clustering, you would then always have a base case that's behind because you wouldn't know what all is going to be studied for at least three months or six months or whatever the window is for the cluster.

Am I understanding that situation to be correct?

MR. CALDWELL: I think there's ways around it, you know, and I understand what you're saying. Clearly the base case I think in most cases that have what I'll call successful cluster, that the base case has sort of defined as a mix of what's already there and what is going to be there in the absence of the cluster, and so there is that mix and there is that interplay but that the reliability upgrades that are going on outside of the process, you know, are taken account of.

Again, I think the key is that, you know, the sequential queuing process is no place to do transmission planning, it's no place to do generation planning, and there must be these aggregated studies that feed in. And I would second the thought that that doesn't mean that there is no place ever for a queue and we just all throw these things in together.

There is no simple answer. I think a lot of people have thought long and hard, and have come up with workable processes here.

In the midwest for example, we have by our count something like 8900 megawatts of wind in the combined MISO SPP queue. And if you put in the non-jurisdictional entity queues in the region also that are impacted here, we're well over, we're at the 10,000 megawatt level. And what we're going through right now in MISO is, if you will, the mother of all cluster studies, at least as related to wind, where we're taking 10,000 megawatts, it's not necessarily the exact same 10,000 that are in the queue but that it's a reasonable representation of where the development for wind could take place over the next five years. Each one of those instances has real generators, real projects, real markets, and we're trying to study that as a cluster.

And it's interesting. One of the results that came out of that, one of the first results that came out of that cluster study was in spite of the fact that supposedly that there was zero ATC available for all this wind, 9,950 megawatts of the 10,000 megawatts was deliverable to the grid and had availability if we looked at it as a cluster. And if we looked at it, instead of a worst case once in ten years, we looked at it chronological simulation of what the grid would look like, so that there were approximately 80 congestion points identified by that cluster study, but only two of those had any congestion more than a couple hundred hours a year and only about ten of them had more than ten hours a year.

And so when you look at it that way, you can begin to make the common sense kinds of things that happen, you can begin to do the transmission upgrades in a logical manner and you're going to end up with fewer transmission upgrades and different transmission upgrades than if you study them sequentially.

MR. HEGERLE: Jim, just so I understand what you're saying, you're saying they essentially wouldn't give you firm service because for an hour or two a year, it was not firm?

MR. CALDWELL: Correct.

MR. HEGERLE: So I mean, aren't there options to

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MR. CALDWELL: There is no effective option other than long-term firm the way the transmission products are detailed today in most parts of the country. There is no effective, you know, network service for example, in the midwest. There's no curtailable firm. There's no ability to get involved in remedial action schemes, as they do amongst the utilities in the west where you sort of pre-you know, some mix of a congestion managed, market-based congestion management scheme and some sort of preloading of if this contingent takes place, you're off or this thing really will trip or that thing will done.

That sort of interactive system-wide planning simply isn't done out of the queue. It's done sequentially, it's done 50 megawatts at a time, and it doesn't work.

MR. HEGERLE: Would your situation go away under an SMD environment where you had FTRs or CRRs, whatever you want to call them instead; maybe you didn't have them full year but you had them part of the year. How's that work for you?

MR. CALDWELL: You know, I don't think these situations will never go away. I mean our grand kids are going to be discussing the next generation. But I do believe certainly that SMD or the rubric of SMD, the principles of SMD go a long way towards making it possible to deal with these issues in a much more common sense way than the sort of Order 888 point-to-point and the sequential queue. That you start down that path and you just end up in the weeds. And that if you start down the path of looking at things as a network, looking at them as a region, having ITPs doing all these studies, you're going to probably end up eventually in somewhat the right place.

MS. McOMBER: Do you think also, Jim, that some of these problems are transition problems with, you know, the establishment of the Regional Transmission Organization that we heard about earlier is in process basically?

MR. CALDWELL: I don't think there's any question that a lot of length of some of the queues was a result of that. MISO's a good example where, you know, the issue of what was in the MISO queue changed weekly or monthly as different transmission, you know, in or out. We're still not quite sure that there is an SPP MISO merger. We don't know what those impacts are.

Clearly getting up to speed was a problem, getting up to speed at the same time when there was this flood of requests was a problem.

So some of that will go away naturally but I will guarantee you that enough of it will not go away naturally just with the passage of time to achieve I think the goal of this Commission to lower the barriers to entry, and that some proactive -- we're not going to have the luxury of just waiting.

MR. ROONEY: John, then Jolly.

MR. JIMISON: Going back to Bruce's original question of how do you assure that a cluster study reflects reality, our scheme is that you form the cluster after you've already done on a sequential basis, if appropriate, the feasibility studies for each of the projects that apply and the impact studies for each of the projects that apply.

You do those impact studies on the basis of the system as it exists plus all those new projects that have posted their bond for upgrade so that you have not just the existing system but those who have made a financial commitment to enhancements, and then you cluster those projects who have reached that threshold.

They have completed impact studies, they are ready to go forward, and a facilities study would examine what kind of a system upgrade would be required to accommodate the entire cluster, would then allocate the costs of that upgrade among those projects in the cluster as a function of their capacity, and they would be required to post a bond for their portion of that upgrade shortly thereafter, so that they too would have a very realistic notion as to what their requirements were going forward.

MR. SIMPSON: I guess my comments would be along the line of the cluster, however, the cluster is done.

The cycle time between clusters needs to be as short as possible to prevent the situation saying that the base case is off because you've got projects that are in and projects that may fall out, and when you put together a cycle and study those projects as a cluster, those projects that are in that cluster need to have the same milestones, the same commitments so that they move through together.

Again, we're advocating one queue, not establishing multiple queues, but one queue and all those projects within that cycle studied as a cluster move together forward to the next step. Those that don't meet the milestones onto the next step, they fall out and you can take those out of the base case.

But you need to keep that cycle period as short as you can. I think PJM's cycle period of six months is too long. I think a maximum length of time ought to be three months, and I know that takes extra work and perhaps extra resources but I think the Commission should really shoot for a shorter cycle period than the current six-month period that PJM uses. Three months, in my mind, is the maximum that generators can reasonably live with in getting results out.

MR. HAYDEN: First off, kind of combining a couple of the comments related to what you just brought up and Mr. Jimison about doing kind of a hybrid sequential than a queue which you brought up earlier, Mr. Jones, and then Mr. Simpson brought up as far as keeping the queues tied.

I would argue that under that sequential piece of your recommendation that the facilities study you could argue doesn't have to be a full blown. You could do kind of a hybrid little shorter study because you know once you get to the queue at that point you're going to look at the conglomerate.

And again I totally agree that the milestones have to be reached. People need to ante up to show that there is a real commitment at which point the full blown cluster study.

There was a question asked a couple of minutes ago on will SMD make some of those problems go away, and the like. Let me address one thing I sort of touched on as it related to the market dispatch or economic dispatch. You know there is a lot of transmission upgrades that are being proposed by various transmission providers that are needed to accommodate the gazillions of megawatts that generators have proposed for their service territory.

Well, one of the things that I would argue, particularly in some of the areas where gas is on the margin and they have a large concentration of old, inefficient units, the assumption they're making and trying to pass on through participant funding is: we will continue to dispatch our old, inefficient fleet the way we currently.

I'm not here to pick on any one provider but Entergy is a case in point how their 25,000 megawatts, and it's just a good statistic to show what I'm talking about, how their 25,000 megawatt fleet, 15,000 of it is eleven five heat rate and above.

Now if you eliminate a good hunk of that 15,000 megawatts, my question is how much of the congestion problems, the transmission problems they talk about in the two to three billion dollar numbers you hear on transmission upgrades goes away. So to the question, yes I believe SMD helps get through and weed through some of this. Thank you.

MR. ROONEY: Thank you, Jolly. I appreciate everybody's participation on this panel.

MR. HENRY: May I ask one more question if that's all right?

MR. ROONEY: Certainly.

MR. HENRY: American Forest and Paper has identified some issues special to qualifying facilities that we should keep in mind as we are preparing or thinking about queuing. I know that some other panelists have QF generators and I'd like to hear if they have any special needs or principles they want to bring to us as we're considering queuing.

MR. CALDWELL: Certainly I have many QF members in my organization. In general, we don't share the issue with the co-generators of net versus gross and all that.

We tend to be stand-alone facilities. But having said that, one place I think we share on the priority list with those guys--and I'm talking about from the wind industry's perspective alone, not from any broader perspective--that once you're interconnected, you're interconnected.

And the idea that if you're a QF and are interconnected and have been interconnected for 15 years, and all of a sudden your contract has run out and you continue in some way, it makes no sense in my mind to go back through the interconnection process.

I think that's a perversion of what it is that we were supposed to be dealing with in interconnection. If you're on the grid, you're on the grid and you're not subject to the interconnection.

MR. JIMISON: I wholeheartedly agree with that point, and would also join on the point of net versus gross. That generation which is used on site and off the grid and stays on that side of the meter is of no concern to the grid and shouldn't be reflected in any of the costs or requirements.

MR. ROONEY: Donna?

MS. REED: Another point I want to make is this. In a lot of situations we're already exporting power to the grid in terms of sales to the host utility, so what is the distinction now if a QF wants to be able to sell power in a competitive marketplace?

MR. ROONEY: Wes.

MR. WILLIAMS: I think from our perspective, probably the key and what we've tried to follow at least is the comparability rule that whether it's a QF, whether it's our own generation, whether it's an IPP, at least from our perspective, we've tried to treat them all the same.

And I notice this issue with the QFs has come up in a couple of cases where interconnection arrangements have terminated with them.

As we look at it from this side at least, it appears to us they have no -- once the existing arrangement has terminated, the contract for interconnection is terminated--they really have no rights on there that we can see.

We are concerned at least that if we were then to allow them to come back in with a new request to do something else, essentially giving them head-of-line privileges, we would in turn be criticized by the other generators.

So I think that's the dilemma that we've got to get through, that for us to treat any one class any different than any other one, we've got to be very careful, as first of all, if we want to do that for a societal point of view, and second that we're protected from claims from the others.

MR. CALDWELL: Again, I think that brings up a good point because I think what we're doing is we're not dealing with the subject of interconnection in the same way. That if you're physically interconnected, there should be no reliability aspect on the grid that needs to be restudied.

If you're talking about transmission service or under an SMD thing, congestion management protocols, that's fine but that's not part of the interconnection process. If you're already interconnected, you're interconnected and there's no reason to go back to the head of some queue or any queue to study the interconnection process from here on out.

You do obviously if you've got to get new transmission service and you're going to do congestion management, but that should have nothing to do with the queue or interconnection period.

MR. ROONEY: Jolly?

MR. HAYDEN: The question that it asked, and it was kind of addressed but maybe I just missed the point, let's use the example of a 100 megawatt generator with a 50 megawatt on-site load.

So what I think I heard from everybody was from an interconnection point of view, I am looking, as a transmission provider, I should only be looking at it as a 50 megawatt generator.

Now what happens in the scenario if at my plant and the widgets I make it is more profitable for me to quit making widgets and just generate and sell back to the grid? What happens to that incremental 50? Is that then a new request to your point?

What is that? Is that a new interconnection request? What is that?

MR. JIMISON: Well, if I've applied for a 50 megawatt interconnection, having 100 megawatts of load behind and that's what's approved, I don't have the ability or the right to export more than that without going back through the process and obtaining the rights as well as the physical capability if that's not built in to do it.

MR. ROONEY: Donna?

MS. REED: I want to reemphasize a point that as far as QFs are concerned, we're talking about loads of less than 50. In a lot of cases we're talking 20 megs or less, and we have historically had the ability of selling that type of power to the host utility.

We're not really asking for any preferential treatment. We're asking for fair treatment. We have gone through extenuous processes of trying to get interconnection agreements done with utilities, and it's come to be a cumbersome ordeal for us because we were being compared to large merchant plants. We were not asking for accessibility to the capacity of the grid more than 20 megs or less.

So in terms of being allowed to export power, we would comply to whatever we initially agreed to, whether it be a request for 15, 20, 50. But I just wanted to reemphasize the fact that our approach is different. As a cogenerator, our main focus is manufacturing. It's not power sales.

We could make available to the grid any excess power if we have it available and it makes economic sense.

MR. ROONEY: Thank you. Wes, you'll be the last one to respond.

MR. WILLIAMS: I just wanted to follow up a little bit, particularly on the comment that was made about once interconnected, you're already there. There's no incremental impacts to the grid.

And I think one of the things that we need to keep in mind, though, is that there is a cumulative impact of all of these generators.

And to the extent that a QF leaves and then wants to sign a new contract, they do contribute to the fault duty on the system, and to the extent that we have other generators that are already queued, we do have the issue of who's on first. And so we still need to look at that, even though they may have been interconnected in the past.

MR. ROONEY: Okay. Thank you. And again, I'd like to say that I appreciate everybody's participation on the panel. Let's plan on meeting here again, reconvening at 2:05. Thank you.

(Whereupon, at 1:20 p.m. on Tuesday, January 21, 2003, the Technical Conference recessed, to reconvene at 2:05 p.m. the same day.)

AFTERNOON SESSION

(2:10 p.m.)

MR. ROONEY: Okay, can everybody take their seats? We're about ready to get started.

As far as the processing is concerned, I think what we'll do is, we'll have the opening remarks and Q&As and let that go on through about 4:00, and then leave open about one half hour for public comments. So, that being said, John, do you want to start off?

MR. BUECHLER: Thank you very much. Is that on? I guess so, okay.

My name is John Buechler. I'm the Executive Regulatory Policy Advisor for the New York ISO, and don't let that fool you. I've been in the planning business for about the last 20 years of my career, so I think I know a little bit about this issue and some of the -- hopefully -- solutions or some of the improvements to the system.

I'd also like everyone to know that I have never met Jim Caldwell before today, so I did not ask him to put any plugs in for the New York ISO system at all, but I do plan on talking about it.

And while we still have some bugs to work out and we're still really in the initial phases of the overall queuing and cost allocation process. I think, conceptually, the process we have does address many of the issues and concerns that have been raised in the morning panels here.

We in New York have a separate but coordinated process and requirements for the integration study queue and for the cost allocation process. The study queue requirements are essentially consistent with pro forma tariff requirements of first-come/first-serve, based on date of receipt of application.

We do have a requirement for evidence of site control and at least a preliminary application to the State Siting Council at the point of application for the study queue.

And the requestor must execute an agreement, send a deposit, and so forth, very consistent with, as I said, pro forma requirements.

That allows the system reliability impact study process to get underway earlier than if we required waiting for much further development of the project in the siting process, which can take some time as well.

However, by the time we get to the cost allocation study process, there are milestones to be included in the class year process, and we do now have an annual requirement. I noted the comments on that just before lunch.

And those requirements are that the system reliability impact study must have been completed and approved by the New York ISO Operating Committee, and that there be a completed application received by the State Siting Council, either through the generation siting process or the transmission siting process, as applicable.

If we were to recommend some principles to be considered by the Commission for effective queue management -- and, again, I will include queue management and cost allocation. I think that's the important part of it; that's kind of where the rubber meets the road here, and many people have mentioned that so far today.

There are these few, and I think they try to address the questions that were raised to this panel. Having common databases, models, consistent study assumptions, study format, is essential, and that permits various entities, not just the ISO staff, the ISO planning staff, to perform the required reliability and impact analysis.

In fact, in our case, the vast majority of developers have chosen that route; have usually hired consultants to perform the study in accordance with the system reliability studies that are a part of our tariff. That, of course, is still subject to review by the New York ISO planning staff, and approval by the Operating Committee, which is a stakeholder committee.

Coordination is needed between the state siting procedures and the ITP interconnection queuing procedures, and in our case, New York State does look to the SRIS process by the ISO and approval as part of their evaluation of the overall siting request.

In turn, as I mentioned before, all milestones for the cost allocation process are tied back to the siting requirements. Queuing procedures should treat generation and transmission projects the same, which we do, and which was also mentioned here earlier.

And the cost allocation process should treat transmission owner and developer projects equitably as well. We have a process that starts off with a baseline assessment, and the baseline assessment looks at transmission upgrades that are needed for local transmission owner reliability requirements and load growth, absent those projects in a class year.

When the class year projects are then included, the entire analysis is done over again, if you will, with the class year projects included on top of those baseline assumptions, and ultimately the difference in the cost of transmission upgrade facilities between those two projects is the cost allocated to developers.

Then there's the separate process that involves an allocation to the developers in the class year, based upon their pro rata contribution to the incremental impact and system upgrade studies.

We believe that this provides a more efficient process for getting through the entire process, as well as for coming out with a more effective and more efficient set of upgrades, if you will, to accommodate those.

In New York State, which is a highly electrically-interconnected system, that works, to have a class year process that incorporates basically the entire state.

We recognize that in broader areas such as the MISO and other parts of the country, the cluster-type concept may have better applicability.

Real quickly, because I notice I ran out of time, a few other questions that you've asked: We do not believe that the critical engineering information infrastructure of the proposed rulemaking will have any significant impact on the processing of the queuing or the interconnection process.

Small generators, in our case, we generally exempt small generators under 10 megawatts and under 115 KV connection, however, we believe it's important that the ITP have the discretion to decide whether those generators should be exempt, and if they are not exempt, they should follow the same processes as any other interconnection project.

Queue position is a property right, and we believe it's generally not practicable, with the exception of the case where only the project ownership changes. If the project size of interconnection point changes, we do not believe that that should be conveyed; that should be a separate project and new request.

Then, finally, we believe that standardization of specific practices by the Commission is unnecessary, and that the adoption of principles such as I discussed on the earlier slide would be appropriate for the Commission in a final rulemaking. Thank you, and sorry I ran over.

MR. ROONEY: That's okay. Thanks, John. Scott?

MR. HELYER: Thank you. I'm Scott Helyer, and I'm Director of Transmission for Tenaska.

I guess we're here to talk about queuing, and the thing that comes out right away when you're talking about queuing is, why do you have the queue? The driver, I think, that's obvious to everybody, and we've heard it discussed several times, is, you know, how are we going to allocate the cost of upgrades to the transmission system when you connect a new plant? That's the issue.

If you dealt with that issue, the queuing process would probably take care of itself. I have seen it happen, and in different places, particularly in ERCOT where we dealt with the pricing issue. We laid out who is going to deal with it, and at that point, engineers are real good about putting a process in place to go run studies and figure out what to do.

In ERCOT, you don't have to pay for anything. That's certainly one end of it. Generators don't have to pay for upgrades to the transmission system. At that point, from a queuing standpoint, the information that I get out of studies is going to help me understand what kind of congestion I may deal with, or what have you, until they may get some upgrades done, if there are any needed at all.

If you want to go to the other side of it and say, generators, you are going to have to pay for something through all the participant funding, I've been here before and said it, and, you know, I'll kind of say it again: Tenaska doesn't have a problem with dealing with participant funding, if that's what we want to do.

If we are going to pay for upgrades, though, for the transmission system, we have got to find a way for us to recoup the value that we're creating through those upgrades. Just getting CRRs is not going to do it. We're going to have to figure out some other mechanism to get us the full value of that.

We've proposed a method in our SMD comments. I have seen others come up with some ideas on how we might be able to do this. You know, we're going to have to get to that root issue, if you are expecting generators are going to have to pay for this.

We're effectively banking upgrades to the system and we don't want to have a bunch of free riders sitting out there on the upgrades that we're paying for.

When you step back and think through some of this, I have to say that transmission planners were real good at planning the system. Generators were real good at trying to figure out how to build power plants and operate those power plants.

Should we consider, you know, dealing with things the way that we've done it in the past and let congestion pricing drive what we need to do? You know, in the past, transmission planners have taken an imperfect set of assumptions, just like they have today, and have been successful in planning the system.

They look at the problems, they come up with a plan, they attempt to execute that plan. If they fail to execute the plan, what do you end up with? You end up with a dispatch of the system, or maybe some higher losses that what you really wanted to have, which effectively, today, is what we're going to call congestion.

And that congestion gets allocated to somebody. As you go down the road with what's being contemplated in

SMD, congestion costs are going to get allocated to somebody. Either the load is going to pay, generation is going to pay, somebody is going to end up paying for that.

If the planners planned the system and tried to execute their plans, if congestion costs got too high for somebody, more than likely, somebody is going to step forward and say, hey, I've got an idea of how to solve this.

We need to try to open up the process in some cases to get access to the data to understand what the problems are in the systems around the country. We don't always have that access.

As you heard earlier, we sometimes have problems getting our hands on the data. We get told that it's confidential information.

We're not necessarily the all-knowing people, either, but sometimes we think that if we all sat down and tried to work collectively, and had an interactive process and an evolving process, we could all sit down and try to figure out how to make this work. With that, I'll move on and look forward to the questions and answers.

MR. ROONEY: Sam?

MR. JONES: Thank you. My name is Sam Jones. I'm the Chief Operating Officer of the ERCOT ISO.

I feel a little bit strange because I come to you from a little bit different model of wholesale competition, and my comments will be centered around that. ERCOT utilized queuing when it opened its first competitive wholesale market in 1996.

As Scott mentioned, the queue was not for determining cost of needed new transmission projects. Under our wholesale competition rules, since '96, which the PUC established, the transmission provider has always added the new transmission that was needed to not only improve the system but also interconnect generation, as long as it was reasonably sited, so there is no cost assignment.

The queue is actually used to determine in our own model, the priority of annual planned transmission service where we had a system whereby loads had annual planned service. And new generation was eligible for that, based on the queue.

There were problems with it, the ones you've heard today, questions like who came first? When did you lose your place in the queue? What were the base case assumptions for the load flows and things like that?

But we moved away from queuing in our new wholesale market, which we opened July 1, 2001, except for the ardor in which we perform interconnection studies.

We still take generation as it makes its application for interconnection and study, in that order. We first perform what's called a screening study to give the generator an idea of how much congestion they may encounter if they decide to site there. Then if they do decide to site there, then there's a full interconnection study that's required. Again, that just more formally estimates the congestion they will see, and gives the generator an idea of what type of transmission improvements may be required to fully integrate them. It doesn't prohibit them from interconnection.

Those study days, there is some delay. We're averaging about 90 days for the screening study and about 90 days for the full interconnection studies, so that's about six months from application to interconnection agreement.

They have been as short as 54 days, and we did have one project that ran about 440 days, but it had some very special considerations associated with that.

The way it works is that our current transmission service model is network service and all scheduled slow. We don't do any curtailments or anything of that nature.

But the ERCOT ISO operations, which operates the whole grid, is responsible for managing congestion. And so as such, we do it two ways. We have an intrazonal or zonal model right now. We have intrazonal congestion that we manage with balanced -- I mean, excuse me, competitive balancing energy bids.

Those price differentials for those balancing energy bids in the different zones is what determines our congestion costs. That is directly assigned to the parties that are doing the scheduling, so there is an incentive then for a generator not to site where they know they're going to have a significant zonal congestion in their deals, because that raises their price, basically, to the customer.

Now the other form is local congestion where it's a local problem and it usually can be satisfied or solved only by one or two individual generators. Then we try to find a competitive solution where we can. Where we can't, we do some out-of-merit dispatch.

Currently, that congestion is uplifted to everyone, but we have a major project underway in ERCOT to directly assign that congestion, and when that happens, then there will also be price signals to generators not to site where they're going to incur local congestion costs.

We use the standard interconnection agreement. It's basically sheparded by the ISO, although it's with the transmission provider, but it's very standardized.

And I guess my final comment is that when generation right now is really receiving a lot of attention in our area as well, the wind generation forms we see are typically large, many megawatts each. We've had a total of a thousand megawatts of wind generation added in ERCOT this past year, and we've got somewhere over 2,000 that's currently being considered.

Unfortunately, where the wind blows and where these units are being sited is not in an area where there's a lot of existing transmission, as other people have commented.

We have a saying that ERCOT -- it's all in West Texas, and we have a saying in ERCOT about only wiring on poles in West Texas is barb wire fences. And that doesn't bring the power back to the Dallas-Ft. Worth area very well, but we're working on that.

In fact, some wind generation now is actually being delayed, not by us -- we will process the application -- but by the builder, because they know that the transmission is just not there yet. And we hope to have additional transmission built as early as this summer on some projects. And we are curtailing wind generation output right now to keep the system stable.

I guess the final comment is what we have really done is reduce delay in being able to interconnect with our system, and what we've done is move that problem-solving over to the congestion management arena, more so than the construction arena, immediately.

MR. ROONEY: Thank you, Sam. Pete.

MR. LANDRIEU: I'm Pete Landrieu, Vice President of Electric Transmission for PSE&G, but this afternoon, I'm taking that hat off and speaking on behalf of Edison Electric Institute and its members, both generation and transmission.

And I'm going to talk this afternoon a little bit about what I'd like to lay out as sort of a three-piece solution going forward, to some of the problems in and around queuing.

First, in the past year, I think -- EEI thinks and their members think that the industry has made quite a bit of significant progress in developing a generic IAIP process, and a number of the people in this room today, I know participated long and hard in some of those sessions.

And first off, what I'd like to recommend is that FERC accept and adopt the consensus to the extent it exists, in that earlier work that was done.

The second piece: FERC has a number of what I would call queuing-friendly initiatives already underway. The movement toward independent RTOs and ISOs should help assure fair administration of queuing and planning and study processes, and the SMD pricing signals should help both guide location of projects, as well as give guidance towards cost allocation.

And, finally, there are some additional things that need to be done, and that's been the topic of today's conference, and we believe that this additional work should take place on a platform whereby the industry can participate in helping devise the right solutions to close the gaps and issues.

So far as large scale resources, transmission owners tend to agree more than they disagree, and they have resolved many issues so far through the NOPR process.

The remaining issues that need to be addressed are more evolutionary than revolutionary in nature.

And the initiatives I mentioned already underway, I think will help guide the process toward a finality. While there have been quite a number of generation projects coming online, and the maps very well illustrate that those numbers have been significant, and they have been increasing over the past three years, yet we've heard today, anecdotal indications of problems for some projects seeming to continue, so that additional progress certainly is warranted and should be encouraged.

Small scale resources are a somewhat newer phenomenon, and the wind generation that we've heard quite a bit about, and understandably, they're a little further back on the learning curve insofar as devising solutions to them, because they do present some different characteristics and challenges to the grid.

And finally, I would want to suggest that FERC may want to conduct a little queue management of its own.

Everything at the same time is difficult to manage, and getting -- the first things need to be first, and I think that in sorting out all the activities, both in the queuing process and the SMD, there needs to be proper ordering.

So far as both developers and transmission owners, they share a strong interest, and that strong interest is uncertainty about their investments. And if what we all want is to create a climate that's going to nurture robust investment and infrastructure, well then, we need to do that by providing minimum risk maximum certainty, proper pricing signals and the RTOs can help in that process also.

Furthermore, clear uniform milestones and restudy provisions. They help promote an efficient queue process and reinforce certainty.

Applicants need to know the maximum cost exposure as soon as possible, and the service providers need to know what equipment and plant they need to order as soon as possible, as well as have some assurance of proper cost allocation and recovery.

There's a general agreement amongst transmission owners and generators that there needs to be one queue. Multiple queues and multiple processes need to be consolidated. FERC should mandate that the industry develop a road map and timetable to move expeditiously from today's environment toward more regional queuing platforms. And as regions develop into RTOs, I think that will want to occur naturally, and FERC will need to pursue the interregional coordination amongst them.

Regarding small-scale resources, EEI has felt for some time that as many of the distribution level resource decisions should be left to the states as is practicable, and the limits need to be based on the engineering realities of the local network. We've heard a lot of things about numbers, but we've also heard today that, gee, the problems depend upon the exact nature and physics of the system. And I think we're going to need to depend on RTOs to accomplish that for us.

We should avoid subsidies for any class of resources and all resources need to be included in the same queue. And really central to many of these things is that we have to respect the physics over the politics in any situation.

And that pretty much completes my comments. So far as delivery issues, you did ask a question there. And EEI feels that since FERC is already addressing delivery issues elsewhere, that they don't need to necessarily be part of the queuing consideration at this time.

Thank you.

MR. ROONEY: Thank you, Pete. Beth?

MS. SOHOLT: Good afternoon. I am Beth Soholt, Director of Wind on the Wires, a project in the upper Midwest, which is working on windpower and transmission issues.

I want to thank the Commission for recognizing this important issue and taking testimony today. I have three main points, and all of the points that I want to make that I really want for you to hear.

I'd like to stress that we need resolution to these issues sooner rather than later. I think you've recognized that, but I really want to make that point. We need clarity on a lot of these issues.

Several people have mentioned that nonjurisdictionals need to be included in the process in the order or whatever mechanism FERC uses. That's really important, particularly in the upper Midwest, where we have a lot of transmission owned by Western Area Power Administration, a lot of wind resources in the Dakotas. We really need them to participate in the process, both in the interconnection and the transmission service process.

And then we really need, thirdly, we really need the rules to recognize the advancements that have taken place in wind development,a nd I think those have been talked about a little bit here today. But I think you can tell by the number of comments about windpower today that the market really is asking for wind and that there are a lot of developers out there very eager to provide the product if they can only get it to market.

And many states in the upper Midwest --

Minnesota, Iowa, Wisconsin, Illinois, to name four --have renewable goals either in statute or in rule. And we have a very supportive congressional delegation, particularly in North Dakota and in South Dakota, that are eager to see those wind resources for a variety of reasons developed in their states. And this all goes to the issue of getting the wind projects through the queue.

We have willing buyers and willing sellers that are ready to go. Wind can come quickly on line, but the queue-in issues do have a big impact on them, since they often deal with pretty short timelines.

The incremental approach is really a barrier for windpower. As has been mentioned here today already, the queue process must allow for a transparent, dynamic, timely process. Time is of the essence. Transparency is of the essence. We really need access to the data, particularly the base case data, to be able to analyze, as has been mentioned here today.

Just as far as specifics and regional differences, I would advocate that FERC set some standard and then allow for some of the regional differences, particularly some of the ones that have been mentioned here today. I think Don Jones mentioned the southwest Minnesota example, and then I think MISO is rightly looking at grouping generator projects into some subregions. I think that could be very beneficial.

One thing that FERC really needs to look at and provide some direction on is the issue I mentioned before of the nonjurisdictionals. Right now, WAPA has a queue for interconnection and transmission service. MISO has a queue. And a project does not always rise to the top of both of those queues at the same time. They're not studied at the same time. That can be a problem. And it is a problem for projects looking to get out of the Dakotas.

Study assumptions are not necessarily the same in the WAPA queue as they are in the MISO queue. I know MISO is working to try to bring in WAPA when they need to do a study with some of the affected transmission providers in the area, but it doesn't always happen. It's getting better, but we really need some FERC direction on that issue.

The issue of providing different kind of transmission product, such as curtailable firm transmission product, could really be beneficial to the queue. I think Jim Caldwell mentioned the planning right now is done for a few hours or a day out of ten years. If we had some kind of transmission product that wind developers could use for their projects, it could do a lot to alleviate I think at least the wind portion of the queue and potentially other types of products too.

So what do we need in the changes to queue policy and practice? We really need the framework and then specifics from FERC to be able to solve these issues, to give the RTOs direction.

We really need to have a combination of best practices either from the New York ISO or from PJM, set those out and let those work in the various regions.

The transmission planning process needs to have rules in place, but it needs to accurately reflect the projects that are actually moving forward. I think that's no different than what some other people have said.

But the last point I'll just make is that the study methodologies at the RTOs really need to take into account the advancements in wind development. The latest generator models, penetration levels, include some kind of a wind forecasting mechanism like the Cal ISO has right now. And then emphasis or consideration again on the curtailable firm transmission product.

Thank you.

MR. ROONEY: Thank you, Beth. Lou Ann?

MS. WESTERFIELD: I'm Lou Ann Westerfield. I'm a policy strategist with the Idaho Public Utilities Commission. I'm also the chair of the NARUC Staff Subcommittee on Electricity.

I would like to preface my remarks by saying, however, that my views do not represent those of either NARUC or the Idaho Public Utilities Commission either as a whole or individually, just to let you know where I stand.

So I'm here on behalf of me, myself and I. As many of you know, I have been a participant, along with other state staff members in the 2(a) NOPR processes concerning interconnection over the past 18 months. And it's been a pure joy and pleasure.

(Laughter.)

MS. WESTERFIELD: But based on those experiences, I would just make some remarks. As one regulator to my fellow regulators seated across the table, I would ask that you not write any prescriptive rules for queuing, and here's why. As you have heard from many of the speakers, and as I've been hearing for the past 18 months, queuing itself is not the problem. The problem is money.

The problem is cost, pricing. The problem is the ability to access lucrative sales contracts in the wholesale market. The problem may also be the ability to also get transmission service, which is a different queue. The problem is also a human resource problem. In many small and mid-sized electric utilities across the country, the same engineers who are working on interconnection requests are also working on build-out to meet local growth, emergencies of course, and regular old system planning for reliability purposes. So I think that's something that we have to acknowledge.

Now having said that, however, knowing what regulators are like, because I've been one for a while, if you must have some kind of prescriptive guidelines, I would ask that you recognize the need for those rules or guidelines to not interfere with or to address resource adequacy, to also acknowledge they might have an impact on safety and reliability requirements, and to also incorporate enough flexibility to allow for regional differences.

Again, getting back to the fact that the industry itself is made up of transmission owners of many shapes and sizes, and regions of many shapes and sizes.

The region I'm from, as you know, is extremely vast in terms of geography and therefore very different from the Eastern Interconnection.

I would also point out to you, I guess probably the most important point I would make other than the first one, is that NARUC of course did prepare model interconnection procedures and agreements, and we have participated very heavily just most recently in the small generator interconnection ANOPR process.

If you're looking for a super-expedited process, I would just continue to plug our model project, which by the way was funded by the DOE. In that project, we did take the best practices of the four large industrial states who have very active small generator interconnection programs -- Ohio and New York, California and Texas.

And that process of course should go out for public comments, so it's not as if we just sat in a room and made this up.

So after having done that, we feel that we have a product that any state could adopt or adapt for its own use to get the ball rolling on small generator interconnection.

I would just note that I hadn't been in the room five minutes before I heard that "D" word, Distribution, come out of your mouths. And of course every time that happens, I get a little nervous. And I would just like to tell you that we feel that the state commissions have a very meaningful role to play in the interconnection at the distribution level, and we would continue to advocate that the interconnection at that level belongs to us.

Other things that may happen past that level such as wholesale sales, of course, belong to you. So I would just remind you that that continues to be our position.

I would also note that one of the things that has come out of the last 18 months of discussion is that in spite of the fact that generators of all sizes would like to tell you -- and this is no slam to Scott or any of my other friends on the panels, but they would like to tell you that generation is of the plug-and-lay variety that's kind of like Legos. It's really not.

All of the transmission systems and distribution systems in the country are extremely lumpy. Electricity, wire construction in and of itself by nature is lumpy because it was built for either what was there or what has transpired or been added in the ensuing years.

So that's just something to keep in mind when you're thinking about some kind of rules on queuing. There are some areas of the country where that might work just fine because they have a fairly consistent system. But that's not going to be the case in very many places because of the way the transmission system was built.

And I would just end by saying that location is really key. One of the things that has come out in our ANOPR discussions is that size at a particular location can be a really chilling factor or a telling factor. A large generator locating on a very small line is going to be problematic. Forget the jurisdiction issue. And some lines have other weaknesses that will be exposed by somebody wanting to interconnect at that point.

So, again, you have to allow I think for specific location issues to be dealt with, and that's why standardizing rules or making them to prescriptive just simply won't work in this industry.

Thank you.

MR. ROONEY: Thank you, Lou Ann. Kim?

MS. WISSMAN: Good afternoon. Thank you. My name is Kim Wissman and I am the Executive Director of the Ohio Power Siting Board and I also serve as a member of the NARUC Subcommittee on Critical Energy Infrastructure Information.

I'd like to thank you for including both siting and critical infrastructure issues in your deliberations, and I'm actually here specifically to try to address those related issues and how they do tie in.

Siting and queuing can work together more efficiently if we can effectively reduce the response time in the queues. And speaking for Ohio, we attempt to be as helpful as possible to respond to daily requests for information from both generation and transmission siting applicants, and also contractors interested in bidding on construction, as well as fuels to supply new projects.

Before the events of September 11th, 2001, much of the infrastructure information needed by the developers was available through interactive mapping techniques on the state commissions' Web site. That has changed. Since 9/11, the state's sensitivity to the interdependence of national, regional and local infrastructure components, the loss of which would have widespread and dire social and economic consequences, has been heightened.

As a member of the NARUC's Ad Hoc Subcommittee on CEII, I can attest to the fact that a fundamental responsibility of a state utility regulator is to assure reliable supply of regulated network services in both energy and telecommunications.

For that reason, state regulators directly support their individual state's homeland security efforts and initiatives. I encourage you to visit the NARUC CEII Ad Hoc Committee's Web site, and there you'll find the activities that are undertaken not only by the various states an NARUC, but there are also many links to other national endeavors that deal with these security issues.

While we once were primarily concerned with disruptions of service due to natural disasters and technology failures, we also now focus on mitigation measures to reduce the risk of failure due to terrorist actions.

In Ohio, we are still trying to define solutions for ways to respond to legitimate requests for information and are concerned with any queuing delays that affect the siting projects.

John had previously indicated he didn't feel that there was any related CEII activities. Having personally been turned over to the FBI, I'm here to beg to differ with them, and I'm very interested in finding some solutions on providing meaningful information to the request while protecting our valuable infrastructure.

Given the heightened concern for infrastructure vulnerability issues, what solutions can be recommended to allow developers and owners of large and small generation projects to acquire information necessary to make effective decisions for site selection and interconnection queue position with the greatest efficiency?

We have to find a balance to protect the critical energy infrastructure information, and we also need to prevent the incumbent utilities and others that may have obtained market power from using that information as yet another tool to keep workably competitive markets from developing.

First, FERC's criteria under its proposed rule regarding critical energy infrastructure policy, and that's the Docket Number RM02-4, must not be abused by utilities to withhold the information from public disclosure of commercial information which lacks legitimate CEII status and that historically been centrally public to these proceedings.

Clear procedures must be instituted at the outset to ensure protection of critical public interest and be carried out by those with specific and qualified experience in CEII; namely, the Office of Homeland Security and its proposed successor department, to vet and review FERC's CEII decisions.

Ohio, other states and NARUC filed comments in this docket and that should be seriously considered in that rulemaking as well as this one.

Secondly, there are a few solutions that are suggested by experience of other agencies at the state and federal levels that might be considered. These suggestions simply reflect experience that are not necessarily endorsed by NARUC, its members or Ohio, but we certainly are looking at these things in the ad hoc deliberations as well as individual states in trying to progress this very important issue.

First, the site selection efficiency is important. There's been a lot of talk on the panels about all parties being interested in prompt approval of viable and cost effective generation projects. The queue should not enable less efficient, less desirable projects to delay or prohibit others.

This will mean that narrowing site selection to a preferred site and potentially a viable alterative. There are a limited number of potential sites across the country. The applicants ought to avoid serious flaws in their selection by considering at a minimum using a point-based site selection system for the siting process.

They have to weigh issues such as avoidance of impacts on endangered species, minimization of ecological, social, agricultural, health and other environmental impacts, the utilization of existing infrastructure ought to be efficient and effective, and there has to be an avoidance of a negative impact on the regional grid interconnected system.

Such information should be available from authorities such as state development departments, state environmental agencies, local zoning boards, mayors offices, township trustees and other local officials. If you're planning to interconnect with an existing substation, the information gained from such agencies can help you decide if your plan is feasible from a societal, environmental perspective before you actually file an application with the interconnection provider.

In Ohio, for instance, the Ohio Power Siting Board staff will provide you with a contact list to help you collect this information. Much of this could in fact be required up front before you can officially be accepted into a queue.

You should conduct your application for siting in parallel with your application for a place in the interconnection provider's queue.

To reduce your time spent in the queue, ask to have your project studied as part of a cluster. For instance, I know a lot of the RTOs are looking at the effectiveness of going forward with this.

You will likely need the results of the interconnector provider's feasibility, system impact and facilities study in order to be granted the siting certificate.

In Ohio, we require all this to be done with and without the proposed facility with all of the other facilities that are in the queue. And we also require that there's no negative impact on the regional grid.

In Ohio this is very important to us because this is now going to require serious coordination between PJM and MISO efforts.

In Ohio we also have a call-before-you-dig program. You have to uncover the existence of below-ground infrastructure before you invest a great deal of time and money in a project. A lot of states have this 1-800 number in service to particularly find out who to contact and what would be impacted.

In Ohio, due to security reasons, we now make a permanent record of these inquiries and provide it to the appropriate utility companies for security purposes. It ought to be considered that we coordinate such reporting procedures with other federal and state agencies as well in order to protect our critical infrastructure.

We also must ask for the right information. The lack of trust from negative experience with transmission owners in past years has unfortunately driven some project applicants to shy away from accepting a transmission provider's feasibility study.

Applicants may ask for more information than they need, thus slowing down the process. They may want information in order to confirm independently the interconnection provider's study results. Such requests may necessitate the use of sensitive data.

In the face of heightened security, the way such information is delivered to the public may have to change. In line with federal and state Homeland Security measures, the U.S. DoE or the FERC may want to consider using the U.S. EPA's public access to off-site consequences analyses, otherwise known as the OCA model.

This model provides the public with read-only access to paper copies through about 50 federal reading rooms across the U.S. A state could consider making such read-only information available in a publicly controlled environment and we ought to coordinate protocols with national homeland security efforts.

We have to be able to provide access to genuine applicants while protecting this critical infrastructure information for security purposes.

Also applicants should know, as well as RTOs should know, who is asking for data. If a project applicant or interconnection provider needs to use a third party contractor to perform studies, a transmission owner will want to be certain that its critical infrastructure information is in safe hands.

Third party contractor personnel who ask for data for the purposes of conducting studies should have security clearance and be certified or licensed experts in their field.

Study results in the wrong hands could pose serious security risks by pinpointing opportunities for cascading outages or threats to the reliability of the grid.

In New York State, for example, even the state regulatory personnel who have direct access to such information have to obtain security clearance as a risk management measure.

On the other hand, there are potentially recent studies that have been conducted that may or may not be public but could be accessible that could give the new applicant some information on whether to go forward or not.

I think we need to really seriously weigh what they need to go forward and make their critical investment to actually request a siting application and/or an interconnection application.

I appreciate the opportunity to be here today and thank you again for including these matters. I think that we really need to look at a very critical balance and though it hasn't been discussed, I think the CEII information is very important in these deliberations. Thank you.

MR. ROONEY: All right, thank you.

MR. HEGERLE: I want to start with a topic that was mentioned by at least Scott and Beth on this panel and mentioned a couple of other times earlier today. You told us that if we get the cost allocation right, we don't need to be here today, that the queuing problem goes away. To the extent you feel that's true, you know, I'd like to know that, and I'd like to know what the prices ought to be, how we ought to do that, and what the pricing structure should look like. I'd start with John down here.

MR. BUECHLER: Okay, Mark. Well there was something that I did address in my opening remarks. The cost allocation, I agree with our previous panelists, is what it folds out, really, and queuing is one of the ways to get there. I propose for consideration the kind of process that we have in New York on cost allocation which does again start off with a baseline assessment, is an open process. The study results are provided to a specific New York ISO committee along the way for both the baseline study as well as the reliability study with the class year applicants included in that process.

We came to this process after probably about two years' almost worth of stakeholder negotiations and filing an approval at the Commission. And it does seem to be working. As I said before, we have a few transitional bugs to work out. We're only in the second round right now, i in the middle of that, so that's what I'm kind of throwing out here for, you know, discussion or questions whatever.

MR. HEGERLE: Scott?

MR. HELYER: Well, I guess as I mentioned, taking the cost out of the generators and just letting the transmission providers plan the system, come up with it, I mean one way of doing it that's been debated is let the transmission providers plan their systems, build what they think is necessary to deal with reliability and then put it into their costs. You know, they can go in for rate cases whether they're at the state level or federal level.

If they fail to get the system planned adequately, you know, for reliability purposes, you're going to end up with congestion. Somebody's going to have to pay for that. And whether it be the load, whether it be the generator, I mean you're going to have loads that want to reach out and try to grab network resources, you're going to have network resources want to try to get the loads. They're probably want to get together with the transmission providers and work something out.

One of the concerns that we have is the working out right now. The working out right now is we're being told use generators, you're going to have to fund these upgrades. Well, to some degree that's all great, well and good that we fund the upgrades, but we don't get to recover all the value of those upgrades. We'll put in an upgrade and say lines that are loaded at, you know, 80, 90 percent in some of the studies. And studies aside for a minute, lines are loaded 80-90 percent in the studies. Now you put an upgrade in and the line loadings go down to 50 percent.

And now I've funded that whole upgrade, somebody comes along and sites a plant right next to me and now they don't overload anything. I have effectively paid for the system for somebody else to come along and use it. And that's what I referred to earlier as a free rider. We've got to find some way of allowing that extra capacity that I've created on the system to be recovered by me. I mean the transmission providers, when they build something that gets put into their rates and they're going to recover through an access fee.

What's being proposed in SMD is, you know, well, gee, you know you fund the upgrades and maybe we'll give it back to CRRs. Well, that's not going to get it. I mean you put and upgrade in, and more than likely the cost at both ends of the upgrade or either end of the congestion is going to go to a very small number if anything at all. We're going to have to work through that issue.

MR. HEGERLE: Well, that's why I'm saying if you are Commissioner for a day, what do you propose, what do you do?

MR. HELYER: Well, we've proposed, you know, one way that we threw out was maybe there's a methodology whereby if I put an upgrade in, I get to choose what the rating of that upgrade needs to be.

MR. HEGERLE: On a constant of varying basis?

MR. HELYER: It could be on a varying basis. I mean depending on what the rating is on a varying basis day-to-day, hour-to-hour is going to dictate, you know, what the grid can do. If I'm being asked, say we're a couple of hundred megawatts short in the system, but the only way, because like was mentioned, you know, the upgrades are lumpy, you put in an upgrade that creates 500 megawatts of capacity in the system. Well, there's 300 megawatts that I'm now paid for but I've no way of recouping it. The transmission provider's going to say thank you very much and they'll go sell it as capacity.

Maybe I should get the revenue for that.

MR. HEGERLE: I see your desire to keep the LMP differential where it's profitable but if I brought Bill Hederman down here, would he say, wait a minute, there's withholding going on, I don't like that.

MR. HELYER: If you put it in on a auction basis that I can bid it in to what-have-you, you know there's, people are going to set that market price. If people don't like the bids I'm putting in, they can probably come along and find another solution to the system, and if somebody else puts a solution in or whatever that solves the same problem, I'm not going to get any revenue for what I just put in. So there are mechanisms and it's not perfect or what-have-you in what I'm proposing, but there ought to be a way that we ought to be able to get together and figure out how to work through some of those issues.

I don't want to create a situation where there's a bunch of gaming going on either.

MR. HEGERLE: Thanks. Sam?

MR. JONES: We got to the position that we're at kind of through the back door I guess. When we started this original methodology whereby the transmission providers paid for that transmission, it was really done for a different reason. We weren't adding a lot of generation in that initial time period and the philosophy was that when we did, it would be pretty evenly distributed across the state and that since it was wholesale competition, all the ratepayers would benefit equally by new transmission.

And in fact it's worked out to where the transmission has been installed actually very evenly across the state. We've completed now about nine major 345 kV additions, numerous 138, and we've got a number that are in the construction and the permitting phase now, and they're scattered from the Rio Grande Valley through west Texas through north Texas.

And it was done originally to put all new generation on an even keel with existing generation since they didn't have to pay the transmission upgrades that the old generation was not charged with.

MR. HEGERLE: If I can interrupt just for a second? What was the deliverability standard at that time to put the new generators on the same footing as the old, so deliverable to a zone or a region of the system? How did that work?

MR. JONES: In that original time frame, we had what was called annual plan service where a load actually had to own or contract for generation on an annual basis, and they were able to obtain annual planned transmission service, which they had the right to at any time, from those resources to their load.

And we were able to I think meet that, the four-and-a-half years that that methodology was in place, I think we were almost always able to grant those planned service reservations with maybe a few minor examples.

The newer model now where it's just pure network service on load ratio share and one point of control, what we found was that we introduced a new problem then because congestion did become an issue as scheduling changed. You no longer had annual planned service. You could change your transmission service day-to-day and elect any schedule that you wanted to and in fact change it during the 24-hour period.

And what happened then people began to schedule based purely on economics and we began to see congestion costs that, well, we probably saw it in the old world, but it just wasn't identified because, you know, you made up for it by how you dispatched units. Now it's identified. And initially we had a lot of congestion costs, zonal and local because there were no constraints. And so very quickly people became concerned about first zonal congestion and so we directly assigned it, which was a rule that was generated by our public utility commission that if zonal congestion exceeded $20 million in any 12-month sliding window, we had to directly assign it.

In essence, we hit $20 million in 14 days. And so we created a methodology to directly assign it and now that zonal congestion has gone way down. We don't see a fraction of what we saw originally.

Zonal congestion has now become a concern due to the amount of generation that we have added under this policy. We've added about 13,000 megawatts in the last two years of total generation in that area. And it's been addressed. And the question will be for us is how well we can assign this local congestion the same way we did the zonal congestion and if we do that right and get the pricing signals right, then that should hopefully send the right messages to the generators that are trying to locate in the future, tell us which projects we need to build from an economical standpoint or economy standpoint with the transmission and also lower that cost.

Our local congestion costs today were estimated this past year to be $150 million. And if you put that against probably a $10 to $12 billion wholesale energy market, that puts it in the 1.2 to 1.4 percent cost of the overall wholesale market for energy in ERCOT. So the key's going to be if we can get that local congestion assigned properly.

MR. HEGERLE: And how does a generator locating within ERCOT recoup its investment? Scott was talking about, I can live with any pricing mechanism as long as I know that I can get my money back. How does that work in Texas?

MR. JONES: Right now they can locate any way they choose. We just tell them what their congestion picture looks like now.

MR. HEGERLE: So they could choose to build to alleviate that congestion or live with it? Is that the choice they get?

MR. JONES: We give them an idea through the screening studies and later through the full interconnection study what that congestion is going to be like and what it might take to mitigate it totally. Now there are some limits. As I said, the transmission provider bills to them at no cost other than they have to provide the generator breaker. But the PUC has to review that.

And I mean if somebody builds 200 miles away from you know main transmission line, I don't think the PUC's going to consider that acceptable. So there is the threat that the PUC won't certify that connection line and all of the interconnection agreements say if it's not certified, then I think the generator bears some of that expense.

And we've seen the generators connect in a very reasonable manner to existing transmission system.

MR. HEGERLE: When you say a transmission owner builds to them, is that the interconnection facilities themselves? Or does that involve network upgrades as well?

MR. JONES: Network upgrades as well.

MR. HEGERLE: And the standard is to be deliverable within that transmission owner's system?

MR. JONES: No, it's network service throughout the state throughout ERCOT's service area.

MR. HEGERLE: So they can deliverable anywhere. I'm getting confused.

MR. JONES: We're not trying to build a system totally bulletproof. Nobody could afford or even acquire those kind of land rights, but we try to engineer the system additions to where we mitigate it down to a reasonable level.

MR. HEGERLE: And lastly, who pays for those upgrades? Is that, that's rolled in, spread across or?

MR. JONES: It's rolled into the transmission cost of service and the loads pay for it on a load ratio share.

MR. HEGERLE: Thank you. Pete?

MR. LANDRIEU: You know I'm going to speak from my PJM experience which recognizes the fact that we're sort of a lot of different places on the curve so far as the journey to SMD as you look across the country.

MR. HEGERLE: You're going to get there though, right?

MR. LANDRIEU: I hope so. I hope so. But PJM probably has one of the longer times to have cooked and used the stakeholder process to come up with the system that Steve Herling described this morning. And it is fairly sophisticated. It depends on LMP. It melds and mixes with the capacity deliverability rights if people want to sell into the capacity/adequacy type market. And it works or seems to work. We haven't heard too many complaints about it, and we've had a lot of generation come and want to do it, and it seems to be fair insofar as where multiple generators, how can you say it, share ownership of a needed upgrade. It can allocate in a pretty fair fashion the portion to each generator.

But until you have markets in areas, that sort of system will not work, so other systems need to exist and are probably appropriate for the time being in those occasions.

MR. HEGERLE: When you say until you have markets, do you mean the economic dispatch like Jolly was talking about on the last panel?

MR. LANDRIEU: I'm talking about really LMP and in your standard market design. My experience has been it's been two elements or maybe three that bring this about. One is the fact that you have the process and queuing and what-not administered by an independent party who does not have skin in the game.

MR. HEGERLE: I think we all agree on the independence.

MR. LANDRIEU: So there's a cost fairness that is engendered. Part of it is the fact that you have an involved stakeholder process that continues week after week, month after month. There are meetings today going on in Wilmington, there'll be meetings tomorrow going on in Wilmington, there'll be meetings the next day going on and I sit in an awful lot of these things but it's not something that the answer's simple to. It takes a lot of stakeholder vetting before you may come up with the right thing.

And then really you have to have that pricing in place to provide the sort of direction that we get in PJM.

Now I think that's something -- I talk about evolutionary, not revolutionary -- because you can't snap your fingers and all of a sudden get these things up and going everywhere but I think the industry is moving and I think FERC has appropriately sort of encouraged the march forward and would ask, as Lou Ann indicated, that you not get overly prescriptive too early, but let the processes, the stakeholder processes and the various difficult concerns that differ because the grid is different from one part to another, you need to let those things work themselves out.

In fact, if this whole issue of interconnecting generators were simple, we wouldn't be here today, but it's not simple. And in fact it's somewhat counter intuitive from time to time because people say well small generators ought to be easy. When you connect them at distribution voltages, depending upon the system you're connecting them to, they can technically and from an engineering standpoint present more of a challenge than putting something larger onto a transmission network.

So these things need to work through the markets, the pricing systems, the stakeholder processes, and evolve in a way that the people have confidence in them, as we've heard some people today say they do.

So I think you are on the right path, and I think my message would be to have you assist, encourage, mandate, however, but move the rest of the industry participants along the path you have already started.

MR. HEGERLE: I imagine pricing is pretty important to you.

MR. LANDRIEU: Yes, it is.

MR. HEGERLE: I know it is to you as well, Pete, but I was thinking Beth with wind generation usually remotely located.

MS. SOHOLT: Right. It is an issue for remotely located wind. I mean I think Pete is right. You are on a path towards the ultimate perfect thing, and we are not there yet.

MR. HEGERLE: I always thought S&D was the ultimate perfect--

(Laughter.)

MS. SOHOLT: And I don't think we will ever get there, but I mean I think the New York ISO and PJM hold some promise in looking at both of their, the way they handle things right now.

But you know I think from a cost-recovery standpoint for transmission providers/transmission owners, something like Minnesota has done. They've got in statute that, as Don Jones mentioned before, that Xcel energy can recover the cost of transmission that is built to deliver renewable energy to their retail customers so they are guaranteed cost recovery on the additional transmission they build.

So I would expect that the generators would pay for the transmission up front, but then they would have the rights associated with those incremental upgrades.

So, you know, the problem comes in to make sure that Xcel Energy can show that the transmission upgrades are actually tied to the delivery of the wind power to their retail customers.

I don't know if that adequately addresses your question, but--

MR. HEGERLE: I guess what you're saying is: to the extent they can show that I'm building this wind generator to serve this retail load, they will roll it in and the retail customers will pick that up?

MS. SOHOLT: Correct.

MR. HEGERLE: I wasn't clear if you were saying that the generators themselves would front the money first and then get it back, or...

MS. SOHOLT: Well I think you could do it either way. I mean they could either, you know, get credits against what they pay for, or it could be done the other way.

MR. HEGERLE: Are you suggesting that this Commission adopt a similar policy, or just encourage the states to do it?

MS. SOHOLT: No, I'm just pointing to that as one example where a state has a preference for a certain type of energy, and because the utility company was concerned about recovering their costs for transmission you know actually have that kind of transmission mechanism in place.

But it creates problems on the other end, too, to actually prove that the upgrades were needed for the wind; that it doesn't have any other system benefits or, you know, that there were prior transmission issues that needed to be fixed prior to the wind projects coming on line.

So you create that kind of a problem at the other end of trying to decide what kind of costs they should actually get to recovery.

MR. HEGERLE: Thank you.

Lou Ann?

MS. WESTERFIELD: Well as you can well imagine, I might have an opinion on this subject.

MR. HEGERLE: Really?

(Laughter.)

MS. WESTERFIELD: As you know, NARUC passed a resolution supporting the notion of participant funding. Now we go a little further than that.

I personally think--and this is my personal view, not NARUC's--that for system upgrades it becomes extremely important to acknowledge when those upgrades are benefitting other entities.

I would urge you to consider something either along the same lines as the transmission credit policy, or even something following the analogy of what states do with regard to residential line extension where if I want to build my cabin up on top of the mountain I might pay $50,000 or $100,000 to have that line extension built.

Then as others come up my mountain, they begin to pay me back for a proportionate share.

I do think that it is obvious that at some point in time--and I think Scott kind of mentioned this in one of his examples--if you put a generator in at a certain location and someone else comes in behind you even five years later, they are going to benefit from the upgrade you paid for and should directly compensate you in some way proportional to their use of those upgrades.

But, you know, definitely in order to--the cost of getting a generator to the grid should be participant-funded solely, and I think most people agree with that.

I would like to mention, or speak to a point that Beth made. I just would remind you that in the case of Minnesota several times over she said it was the State of

Minnesota's policy.

I do firmly believe that matters regarding favoring any type of generation, any type of renewable generation or renewables in general, or whatever type of generation, is a matter of state and federal policy for lawmakers.

I think that if a state legislature wants to adopt a policy like that--and I can give us another example that the State of New York has a favorable subsidy policy for certain types of small generation projects, solar panels, and many other states have similar policies.

Or if Congress should adopt something such as the Wind Tax Credit I think would fall in that category, too, but let's not be too hasty to jump into that boat of trying to overstep our bounds into those policy matters which are probably more appropriately legislative.

I will just stop at that point.

MR. HEGERLE: Let me just ask a clarifying question. You said that the generator interconnection stuff should be participant-funded.

MS. WESTERFIELD: Right.

MR. HEGERLE: But you also mentioned "credits," transmission credits.

MS. WESTERFIELD: Right. And for any system upgrades, as they are used by other entities if you locate your generator at a particular point and you pay for an upgrade and then a couple of years or five years later someone else comes along and builds a generator and puts a generator in right next to you, they should pay a portion of that.

MR. HEGERLE: Okay. So you're not talking about--

MS. WESTERFIELD: For benefitting from that upgrade.

MR. HEGERLE: Right. Right. I don't disagree with the concept, I'm just making sure I understand.

MS. WESTERFIELD: I'm not sure that the assignment of rights of any kind in any way supplants the need to actually directly compensate for that investment. You know, if you are going to come along--there should be no free riders, that's what I'm trying to say.

You know, one way that you're approaching this is through the assignment of rights, but probably more important to developers of generation projects is some kind of compensation for the actual investment made.

MR. HEGERLE: Thank you. Kim?

MS. WISSMAN: Thank you. I think I'm not going to endorse anything in particular. I would like to ask that you take a few things into consideration in doing this.

First and foremost, I think that Pete hit it on the nose. The markets have to be in place. If the markets are in place, the right decisions will be made.

We really need the right price signals. We really need working markets to drive the generators to make the right decisions.

I also think one of the other panelists mentioned that you've got to let regional planning techniques take priority over everything else.

Certainly there are upgrades that are required for reliability purposes. There is no question that these ought to be uplifted; these ought to be in access charges. Reliability ought to come first and foremost.

To the extent that there is an upgrade that is undeniably due to a particular generator, I think probably the generator ought to be paying. It ought to be directly assigned, but if there are public benefits derived it needs to be uplifted.

In the end, I am not strongly endorsing anything because I believe that in the end the ratepayer is going to pay ultimately either through the transmission or the generation. The new generator is going to take that into consideration if they are responsible for the payment in their competitive analysis.

So I will leave it at that.

MR. HEGERLE: We just need to make up our minds.

That's all there is to it, right?

(Laughter.)

MR. ROONEY: Yes. There appears to be different opinions as to whether the queue position should be treated as a property right. Can each one of you give me your position on that issue and the reasons why?

MR. BUECHLER: Yes. On property right, as many people have talked today, each interconnection project is looked at to assess its impact on the system reliability generally. And that depends on the characteristics of the interconnecting, let's call it, generator or transmission facility as well as the interconnection point on the system.

So the only way that we see that a property right might be created is if that were the definition of the project, maybe plus or minus five percent or ten percent or whatever was discussed earlier as well, but basically the same project, the same physical generator, size, interconnecting at the same point, if the developer of that project is taking it through the process and chooses to sell that project to someone else, then to me it could be the same project and it could convey property right and retain its place in the queue and retain its place in the cost allocation process if it has gone through that.

But other than that, I would not recommend a transferrable property right.

MR. HELYER: I think we would probably say the same thing. I don't have a problem with if somebody has put in a request at a particular location and has got certain characteristics, if that developer wants to sell that project to another developer, it shouldn't lose its place in the queue.

We would be opposed, for example, to say someone putting in a request in Miami and then saying, okay, I'm going to sell my queue position to somebody who then wants to, instead of putting the plant in in Miami, wants to put it up in Minneapolis. That would be a little bit of a problem.

But if somebody wanted to just acquire the project at Miami, fine.

MR. JONES: I guess really only the comment I could make is just based on our experience in actually allocating a queue for transmission rights earlier, and I may be stating the most obvious thing in the world. But I think if you do that, you just have to make the rules very clear and very explicit so that everybody understands what the process and what the rights are. Otherwise, there's going to be an awful lot of arguing over, you know, who had the right and what the rights and process are.

MR. LANDRIEU: Yes. And I'd say like projects in like locations. There should be an ability for somebody to either transfer a project, or if in the course of a project for whatever reason they find they are not able to carry it through, they should have a reasonable time period in which to try to find somebody to capture the value they may have created in getting as far as they went.

MR. ROONEY: What kind of time period would you be looking at?

MR. LANDRIEU: What our stakeholders pretty much ended up at was one year. So you have a little bit of time, but not a lot of time, but enough time to say is there somebody who would like to take ownership of this or do something similar and carry it forward.

Now it's different. There's a different issue when you have plant retirements. Let's say an existing plant that's been there 40 years decides it's technology is obsolete and is going to close. In that case, they get in PJM three years. The thinking being it probably takes a little longer to find somebody who's going to do the studies to see if it's worth redeveloping, repowering, bringing new technology in and whatnot.

So they are able to hang onto that as a property right for three years.

MR. ROONEY: Beth?

MS. SOHOLT: I guess I say no to making it a property right. If it's the same interconnection, same size project, yes, as others have indicated. But if it's a totally new project, no.

I just think if you make it a property right, it makes the queue process become more intractable and harder to deal with than we already have today. And so if it's a similar project, you know, same interconnection location, same size, yes, but other than that, no.

MR. ROONEY: You're saying -- what happens if it's a different type of project? Same size, same location but maybe a different type. Do you have a problem with that?

MS. SOHOLT: I'd say no.

MR. ROONEY: All right.

MS. WESTERFIELD: I think I would agree with everybody else that's already spoken. I just think that there needs to be some flexibility and maybe even a case-by-case look. Maybe it's not a good idea to say that either it is or isn't a property right. Because you don't want to get into a situation where someone comes in and is gaming the queue or any other part of getting onto the grid by switching ownership or ownership form.

So I guess I would just say that maybe it should be case-by-case or flexible.

MR. HEGERLE: So you'd leave room if, for instance, I ran out of money on my project and I sold it here to Jan and she stepped in my shoes, that would be okay?

MS. WESTERFIELD: Yes.

MR. HEGERLE: I just can't stand in line so that I can give it away to somebody else?

MS. WESTERFIELD: Right. But if it's just passed from one owner to the other to avoid the fact that bottom line, nobody has the money to build it, that's not a good idea, because it certainly would wreak havoc with the studies and the other people who are legitimately in the queue.

So you want to avoid I think both sides of that.

MR. ROONEY: Kim?

MS. WISSMAN: I believe size, site and technology, sameness, I think it ought to be transferrable. I'm not sure if I have any thoughts on time limit. I'm not sure that's really applicable, but I do think in today's market that it ought to be transferrable if somebody's willing to come in and pick up the pieces if you can't carry through.

MR. ROONEY: Beth?

MS. SOHOLT: I guess I just have a question for Pete, if I may. If you allow the next person that comes in or the person who is in the queue a year to find somebody to step into their project, is that what you were suggesting?

MR. LANDRIEU: I am not sure that the time is a year, but it's definitely not the three years that you get for a retirement. It's somewhere in the shorter timeframe. And the concept is that once a person finds out he's not going to be able to carry through a project, there's a certain time it takes to unwind what he's done already. He probably has equipment, turbines, generators, a site he's either purchased or is in the process of closing on.

And you don't unwind that in a day. And the thought is to give him time as he's unwinding to see if he can locate somebody who would like to step into his shoes.

MS. SOHOLT: And my only -- that's what I thought you meant. And my only comment about that is if we have a queue process that's supposedly moving faster, you know, then hopefully more than on a yearly process, if you've got somebody that's, you know, holding up the queue. I don't quite know what you do with that year time.

I mean, I realize there could be some amount of time that a project developer gets to look for somebody else to take over their project, but if that becomes a queue clog issue, then a year seems like too long timeframe.

MR. HEGERLE: Everybody else behind him shouldn't have to sit there twiddling their thumbs waiting.

MS. SOHOLT: That becomes a barrier in itself.

MR. LANDRIEU: Although I'd like to suggest there's another side to the coin. And that is to the extent that you can find somebody to step into the shoes, you actually smooth some of the queuing study process, whereas, you know, if you cut it off too fast, start redoing studies and then somebody comes along and says, oh, that is a great location, you tend to get a very --

MR. HEGERLE: What you were going to pay for, I now have to pay. But if it's a year, that's probably too long for people to wait. If it's a month, it may be too short, but there's some number that's reasonable.

MR. LANDRIEU: It's somewhere in there.

MR. HEGERLE: I'm seeing nods even in the audience.

MR. ROONEY: And if you had a change in ownership and that's the only thing that changed, then you really wouldn't need to do another study. Is that you all's position? No?

MR. BUECHLER: It would not be mine, no.

MR. POOLE: I have a general question that I'd like to get your thoughts on, and that's relative to milestones. There's been a lot of discussion earlier on some of the other panels about milestones, and if you miss a milestone, whether you get out of the queue.

I guess my thought is more a question of when you set milestones, do you set soft milestones, medium milestones or hard milestones? And when do you put them in? Okay. If you make it a really tough milestone like you've got to buy the land the first day, then some people can't come in. Or if you say you can lease it with an option to buy and you get an air permit and that's the beginning milestone.

That's my kind of thought process is should you -- obviously milestones should get harder as you go along. But should there be a time period over which those milestones progressively go from weak to heavy? Do you see a set timing for those?

MS. WISSMAN: I'd like to comment on that. And again, I think that it's really important to try to coordinate the queuing with the siting processes. I know not all states have effective and efficient siting processes, but they can go hand-in-hand.

I don't want to speak for the RTOs or transmission owners and in what they see as appropriate milestones. But I think first and foremost, they need to require some site-specific site selection studies before they accept anything.

Certainly in the siting process in Ohio, we require milestones as we go, if you will. We don't require that the land be purchased, but they -- and we don't even look at land issues, but we more often than not see that they have an option on the land.

I guess I don't have any specific hard/soft from an RTO perspective. I would just ask that they look very seriously at the effect of siting processes around the country and try to coordinate with those, because it really will I believe help the queuing process as well as the siting process if these are in parallel.

MR. LANDRIEU: The milestones should get progressively harder or substantive. That just seems to make sense. You don't want somebody who is this much financially committed to have to be this much, you know.

But I think what's important for the industry, this is an area where I earlier suggested that just as over the past year there's been a lot of collaboration to come up with the consensus to the extent it exists, this is an area where I think further work could be done to develop something.

Because it would be nice, it would be more efficient to have clear and uniform milestone provisions sort of wherever you went as opposed to, you know, having a different set of local traffic rules when you go from state to state, region to region. And it's the type of issue that I have a hard time believing that regional variation is easily justified.

MR. HEGERLE: I think where we're trying to go is that -- this morning I was talking with a representative from Entergy and someone in the audience accused me of saying we should be throwing people out of the queue. And I was saying, well, you know, I didn't mean it so pejoratively, but it's true. You don't want a lot of speculative projects in the queue because you want the real ones to actually get through it in a timely manner.

So I think where Bruce was headed with his question really was, well, how hard should they be up front? give me an example of what ought to be done to make sure that the queue is real and that people really are there to get a project in. What should we do to weed it out? That's I think where we're trying to get to.

MR. BUECHLER: To that question, I think the coming-in-the-door criteria should be fairly stringent. You've seen the summary results that you asked for from this morning's panel, in terms of number of projects in queue, and, you know, how many projects fail, and it's over 50 percent, just by those numbers, certainly.

That's a lot of time and effort on the part of many parties, but certainly the transmission providers, in doing analysis and things for projects that, for many reasons, certainly, but, you know, don't wind up being there.

So I would advocate a stricter coming-in-the-door requirement to evidence things such as site control. Again, it doesn't have to be ownership at the time, but that it's a real project with a specific interconnection point that the developer has gone to the local transmission owner and comes in with a project that can, in fact, be studied, has a point on the grid, has a breaker position on the bus, if you will.

MR. HEGERLE: Can we go that far without transparency, so that people can actually see the power flow models and what you have, or does that sort of have to fit hand-in-hand?

MR. BUECHLER: Yes, yes.

MR. HEGERLE: It does?

MR. BUECHLER: And how do you answer those questions? Now, you know, you could allow projects to take a queue position before they are at that point, but it just doesn't seem like a reasonable thing to do.

And then I would support more stringent or further development down the line as well. I guess I maybe differ a little bit with Pete in terms of the standardization of requirements in this area, from a siting standpoint.

Without mentioning the "jurisdictional" word here, I'm not sure how the Commission gets by the fact that different and different regions have different siting processes and requirements. And so, it seems to me, in fact, just the opposite point I had tried to make earlier, is that that seems to me an example of an area where regional differences probably are going to be needed, if only for things like timing and so forth of those processes.

MR. HEGERLE: I believe Scott's up here first.

MR. HELYER: I think you've got to take a look a little bit at exactly what the issue is as regards the criteria. There are things that I think the generator has completely in their control, and there are some things that maybe they don't.

If you're looking at saying, do you have all your permits, you know, in place, for error, and all that type of stuff, that sometimes is not completely in control of the generator to deal with all of that stuff. Something from the standpoint, though, of having site control, you know, probably is in the control of the generator.

Do you bump somebody out of the queue completely because they miss a milestone? Maybe not.

It's probably a case of if they're not ready to proceed to the next level because they don't have a milestone met, maybe they slide down a notch in the queue and if the person behind them is ready to proceed, well, then, they get to move up.

It's not just the case that you completely bail out and go to the bottom of the queue, but you keep moving down until you are ready to proceed. That may be a way of dealing with some of that, maybe a little bit of a softer way of approaching it, rather than bouncing somebody out of the queue.

MS. SOHOLT: I have a couple of ideas, and I can provide more specific comments, the written comments that come in, but I think some work needs to be done up front before they come into the process. But as people have recognized, that requires that the generators have access to data, and, you know, that's going to be an issue, hopefully, that we can resolve.

I think the milestones need to be realistic. We don't want to set something that people are going to start slipping right away again, once we set them. I mean, they really need to pass the smell test to know that people are going to be able to meet them, so that we don't have this problem again after the Rule is promulgated. But, so, those are my thoughts for right now.

MS. WESTERFIELD: I have to say that when I think of milestones, I think again of erring on the side of having few, if any, and also having them be soft. I think that the industry is clearly in a transition period where the imposition of hard milestones, you know, one strike and you're out, would be counterproductive to trying to get as much generation on the grid as possible, which seems to be an overarching goal of yours.

When we were doing the NARUC model project, we felt -- the state staff members who participated in that and the Commissioners who oversaw the process, thought that the milestones should be harder on the side of the transmission provider performing studies and meeting deadlines and so on, because they are the ones, after all, who have a lot of experience in this area, and softer on the side and practically nonexistent in our model with regard to those who are actually applying to interconnect.

Again, I think that from what you've heard from the panelists here today, that's fairly consistent with what they're doing. They're not really anxious to take the giant hammer and hit someone on the toe and say, you missed a deadline, so I'm breaking your toe; you're out of here.

So, you know, I think that the approach that has been taken, in reality and in practice, has been fairly soft up to this point. You know, I think that if it had been hard, you would have heard about it from the generators, a lot more frequently and louder.

So, you know, I just would urge some caution that while I think it's important to get the studies done in a timely fashion and to meet milestones that you might create through a rulemaking or that states might for rules at the distribution level, that, you know, we know who we're dealing with there and whose feet we're holding to the fire, because we have been doing it for a century or more.

But I would say that the generation or wholesale market idea, although, in effect, for the past ten, almost 11 years now, you know, is still an immature market. Otherwise, we wouldn't be sitting here and we wouldn't be worried about SMD in our sleep.

MR. HEGERLE: But don't you need some kind of hard standards on the generator side for uncertainty of what your costs are going to be? Unless you adopt a pure roll-in of all interconnection and upgrade costs, you know, I need something to know whether or not the guy in front of me is actually going to be there, to know what my risk is; isn't that true?

MS. WESTERFIELD: No, I don't think it is. I mean, I think it's just the nature of the beast, that you're going to have some projects drop out. I mean, I guess another way of coming at that from another direction is that if we get to a point where the energy and energy trading industries would stabilize financially, that we might not even have to worry about that.

I think that there would be fewer people dropping out, but I think you have to presume that anyone who would go to the trouble and the pain of going through the process of putting up the initial money necessary to get in, to apply to be in the queue, and to perform the initial study, at least has that much good faith.

I mean, for what you've heard today, a lot of people drop out after the feasibility study is performed, and I think that's going to continue. You're still going to have a lot of people who are entities that are speculating. They are speculating and hoping that FERC won't impose price caps in their region, and that they will be able to recover unlimited amounts of dollars on a project.

I think that this is all very interdependent and dependent on the financial viability of the industry in general. I'll just leave it at that.

MR. HEGERLE: Right, but I thought that speculation is exactly why you'd want hard milestones, so that you'd weed out the speculators from the serious project developers.

MS. McPHERSON: Well, is there a clear line between speculators and serious project developers?

MS. WESTERFIELD: No, absolutely not, and I'm not sure that it's entirely healthy in a competitive environment to weed out speculators. I mean, if you had gone through the process of weeding out speculators in other competitive markets we have, they might not ever have developed as they did. You know, I think that's part and parcel of competition. If you buy into that model, you're going to have speculators.

MS. WISSMAN: I'd like to echo Lou Ann. I think she's right. I think we need to be real cautious about just throwing people out of the queue.

On the other hand, I think we also need to be careful not to just enable those with deep pockets. I have an Ohio Power Siting Board meeting today, and we're doing some housecleaning, and there were seven projects on the agenda today that have gone all the way through the siting process, so they have paid all their siting fee applications. They probably have interconnection agreement cases before FERC as we speak, and they now have announced cancellation, and we're cleaning house and basically doing away with them on our docket.

It wasn't that they were speculating; it wasn't that they were trying to abuse their place in the queue. They had legitimate endeavors that they were trying to pursue, and it just so happens it didn't come to fruition.

So we need to be careful to weigh that imbalance between enabling those with deep pockets and just simply throwing folks out for not meeting a deadline.

MR. ROONEY: Would you want some sort of cure period, and if so, how much time would you allow? Or would you allow it?

MS. WISSMAN: Again, I think that it's difficult to say that, and I think that in today's market, given the financial situation, I think we need to be careful, and we need to give a little flexibility. I don't know whether it would be appropriate. You know, if we were back to normal times, which I'm not sure we would ever have, if we would want to put a hard deadline on it.

I'm not sure that's a fair way to approach it, because I think everything is case-specific.

MS. SOHOLT: One quick comment: I know we've been talking about generators here, but one of the barriers right now with some of the queue issues is the transmission providers and the RTOs having a timely process that's going forward.

And so I think a little thought needs to be given to setting timelines for RTOs to process things in a timely manner, at least raisin that issue that that can also be a barrier to queue processing.

I know that a lot of the RTOs and regional entities are undergoing a lot of heavy workloads right now, but sometimes a project can't move forward, simply because they are waiting for an answer from an RTO who is coordinating with a transmission provider and ITP to get an answer back to the developer.

MR. ROONEY: Okay. That leads me to another question, and that relates to the cluster study approach. And I've noticed that there have been kind of differing opinions to the timing of the window itself.

Assuming you agree with the concept of clustering, do you have a thought as to what the time or window ought to be. Ninety days, 180 days? And, if so, why? John, if you want to start.

MR. BUECHLER: Since I'm advocating that approach myself -- I heard the debate this morning, and as I said, New York's current process is annual. We are still transitioning, if you will, into that process.

Six months, I guess, is what PJM currently has. I find it difficult to see how, from a practical standpoint, knowing how many issues get raised in this kind of a process, we can bring it back to shorter than six months. So, six months seems to me, right now, from a New York standpoint, seems like a tough way to get there, but it seems to me like maybe a reasonable number, and shorter than that, it seems to me, would be fairly difficult.

Now, it would depend upon the situations. In New York, basically we have the cluster of any project in New York meeting the certain milestones that I mentioned before. Certainly, in a much broader region in other parts of the country, I think you could, depending upon how you pick your clusters, you might be able to shorten the time period.

MR. ROONEY: Scott?

MR. HELYER: No process is perfect. I guess the concern with the cluster study is that it kind of gets into how many times you're going to re-study. You know, you group a bunch of people together, and you iterate through and you iterate through, and on the one hand, you sit there and say, yes, it's going to be three months or six months or a year, but then you throw in the re-study and who knows when you're going to get done.

For that reason, I mean, I would advocate that you need to do something very quickly, a three-month type of process or what have you.

I have debated this off and on with different folks on the planning side or whatever, as to what can we do from a study perspective? I know the concerns they have with can they really turn things around fast enough and come up with something that makes some sense.

But like I said, the flip side to that is you do six months and then you've got a re-study and then you take another three to six months and who knows when we're going to get done. I mean, we can't afford to have a process that is going to take two, three, four years to ultimately determine what kind of upgrades we're going to have.

So I guess I'd advocate that it's got to be as fast as possible, and three months is something that I would suggest.

MR. HEGERLE: So as long as you can get your money back on a given project, in a sense, you'd pay more in order to get it faster. If you had to choose between money or time, as long as you're guaranteed you're going to get the money back somehow, you'd rather get it going?

MR. HELYER: We need to get it going. I mean, if we had a process in place, like I said earlier, to try to -- that said here's how I'm going to get all of money back or what have you, then there's -- I don't have as big a problem; we just need to get on with it and get myself connected.

MR. ROONEY: Sam?

MR. JONES: I don't know that I can set a hard time. We do it based more on need than anything. Our interconnection studies don't identify specific projects normally that will be built in connection with a generator; they just more identify what might need to be built to handle congestion as that generator comes online.

Then we follow back with regional planning groups that are basically facilitated and kind of chaired by the ISO to study the needs of the regions where we're building the transmission. And we address the problems that are there at that time, so, in effect it's kind of default cluster study.

Once a clear set of projects, or a project falls out of that process, it's designated and approved, and then I think the next time it's looked at, it's based more on need. There may not be hard need in that area again, because maybe there's no new generation projects or problems, whereas, say, in West Texas, with the evolving wind, there may be a real high priority to circle back very quickly, but there's no hard time.

MR. ROONEY: Thank you. Pete?

MR. LANDRIEU: I'd echo that there's no perfect number, and we heard this morning, I think, a lot of the people talk about the realities of the situation govern whether or not maybe it's a load flow issue or a stability issue or a short-circuit issue.

And these things are different, and can involve different complexities. And as an engineer, to me, the answer is, it's the amount of time that it takes to do the study in a way that justly reflects the engineering realities of the situation at hand.

And maybe that's somewhere between three months, six months, one year, most of the time. But if you look historically, generation projects pretty much had a boom/bust type of existence over the years, and I expect RTO staffs are going to find there are times when they are challenged and have trouble meeting a timeframe, just due to workload.

There may be other times when a lot of projects are withdrawn where maybe they are looking for work to do and things move very expeditiously. So I don't think there is a single "right" answer.

The thing that needs to be addressed, and I think the Commission's move toward ITPs, RTOs, ISOs, the independence thing means that there will not be unfairness or arbitrary foot dragging.

The studies will not be prolonged because the folks are out on the golf course too often, that sort of thing.

But to a certain extent, it is really almost like a "just and reasonable" amount of time, you know, whatever that is.

(Laughter.)

MR. HEGERLE: We know it when we see it, yes.

(Laughter.)

MR. ROONEY: Beth?

MS. SOHOLT: I think it is hard to put a time frame on it, but I think the New York ISO process went through your first one and it took a year, basically, 12 months or something like that. So that seems to be reasonable.

But on the other hand, if there is a specific situation that needs to move more quickly than that, I would like to think there would be the flexibility to get a study together quicker and be able to have it addressed.

I mean I think just to use the MISO transmission expansion planning process, their first one is looking at, even with lots of input from a lot of different stakeholders, you know roughly 18 months. And that is pulling a lot of data from scratch and getting it put together. At least I think that is roughly their goal.

Then probably annually, an annual update after that. So those are a couple of guidelines.

MR. ROONEY: Lou Ann?

MS. WESTERFIELD: Well as a Westerner, I have to point out to you that of course we are behind everybody else in forming RTOs. We are piddling as fast as we can. If you'd just quick issuing other NOPRs, we might get there.

(Laughter.)

MS. WESTERFIELD: But I would just point out again that I do think there should be flexibility not just regionally but noting that there are still vertically integrated companies that are small to mid-sized companies, again with human resource constraints.

But I would say that I don't have an opinion on clustered versus sequential. I think that you should leave some flexibility there. And I will give you an example of why.

In Idaho we have a mid-sized utility, our largest, Idaho Power, which serves Boise and what we call the Valley Area of Idaho, which means not the mountains, the easy part to serve.

But anyway, over the past two years, they have sequentially interconnected 85 projects. We are talking about a staff of five or fewer people. I think it is hard to argue with that kind of success in that kind of environment.

I mean, no, it is not the large-scale success story of say a PJM or a New York ISO, but for a region like Idaho which is sparsely populated but has a lot of interest in a lot of renewables available, and we still have a very favorable state QF policy I might add with a six cent price and a 20-year contract now.

So, you know, I think you should have some flexibility there. I guess the way I look at it as a state regulator is if there is a problem you should be hearing about it. But if there is not one, you know, if it ain't broke don't fix it.

MR. ROONEY: Thank you. Kim?

MS. WISSMAN: Thank you. I think there is no definitive answer on an appropriate time frame. I would be happy to help you folks determine what is just and reasonable.

I think clearly the words "as needed" is going to drive what the appropriate time frame is. As Pete said, we have had boom/bust cycles but even those have been regional in nature. Maybe we will have some floating consultants, who knows, just move from RTO to RTO.

But again I think it is going to be the market that dictates what is going to be the appropriate time frame for something like that.

MR. ROONEY: Okay. Thank you. Scott?

MR. HELYER: Yes. I think what you just heard was some of the angst or whatever in everybody trying to figure out what to do with it. I mean, as we started the whole thing and talked about, you know, the engineers are going to want to take the time to try to do it right.

You know, is there a right answer? I mean obviously our preference is to try to do it as quickly as we possibly can. You know, like I said, it has taken three or four years to do it.

The engineer in me sits there and struggles with that all the time. You know, how much time do we spend to get to the right answer? Is an 80-percent answer good enough? Is a 90-percent? 95 percent? How far do you go?

You know, we are trying to deal with a set of system studies as you've heard before to where we're spending a lot of time looking at one hour, maybe two hours of the year trying to figure out how do we assign these upgrades, and are we really getting a perfect answer? No way. We are nowhere close.

You know, we are going to have to work our way and feel our way through some of this stuff, or whatever. The message I guess I want to leave you with on that is the faster we can make it happen, I think the better off we are all going to be, recognizing that there's going to be times where you're just going to have to work through some difficult issues.

MR. ROONEY: Thanks. Pete?

MR. LANDRIEU: Yes. I would echo a little bit that I agree the faster is better than slower, and that if we all share a commitment then certainly we have found in talking about this thing within EEI that the generator developers want very much to, as soon as possible, know their maximum cost exposure going forward.

Similarly, the transmission providers want to know with a certainty what necessary plant and equipment they need to procure and complete design on and get on with the construction.

So from a common goal standpoint, we all want certainty as quickly as possible so that the investment can happen.

Just trying to put a singular number on it may be difficult for many of the reasons that we have discussed these past few minutes.

MR. ROONEY: All right, thank you. Sam?

MR. SAM JONES: I might just make one comment, too, that I think there are other factors we are finding that really are changing the work we are doing.

There is never a perfect answer, and I think everyone is aware of that. But we encountered a phenomena here just within the past few months that I think Jolly Hayden mentioned earlier where the newer efficient plants are coming on line in ERCOT.

Some of the older, less efficient plants which were very strategically sited for congestion are no longer economic to run and we had a case where one entity walked in and proposed to mothball about 4000 megawatts of generation, some of which was very key locations for congestion.

That totally changed our requirements on our planning group as we determine the need for more contracts. It changed siting opportunities. It changed existing transmission base cases. And so no matter how well we do it, it is a changing world out there.

MR. ROONEY: Thank you.

That being said, I think as I indicated earlier, we are going to open it up to public comment. So if anybody has any comments they want to make, or questions, please step forward to the mike here on the left.

(No response.)

MR. HEGERLE: They've had enough.

MR. ROONEY: Apparently everybody has had enough. Anybody from the staff here have any other questions they want to ask?

MS. McOMBER: Just one more thing.

Kim, you mentioned in your presentation about the web site, to refer to the web site for more information on how to do that, and you did not give out the address. Do you want to go ahead and give that out, if you've got it handy, for the record, please?

MS. WISSMAN: Um--

MS. McOMBER: I know it has been many, many moons ago since you mentioned it.

MS. WISSMAN: It's www.naruc.org, O-R-G. Thank you. And it is under Ad Hoc Committees, the Critical Energy Infrastructure.

MS. McOMBER: Thank you.

MR. ROONEY: Okay, anybody else?

(No response.)

MR. ROONEY: With that being said, again I want to thank everybody for attending today's conference. Again I want to encourage everyone to submit comments, but do it by February 4th. Thank you, again.

(Whereupon, at 4:00 p.m., Tuesday, January 21, 2003, the technical conference in the above-entitled matter was adjourned.)